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BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
KRISTIN K. MAYES, CHAIRMAN
GARY PIERCE
PAUL NEWMAN
SANDRA D. KENNEDY
BOB STUMP

IN THE MATTER OF THE APPLICATION OF THE ARIZONA ELECTRIC POWER COOPERATIVE, INC. FOR A HEARING TO DETERMINE THE FAIR VALUE OF ITS PROPERTY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RETURN THEREON AND TO APPROVE RATES DESIGNED TO DEVELOP SUCH RETURN	DOCKET NO. E-01773A-09-0472 **MOHAVE ELECTRIC COOPERATIVE, INC.'S NOTICE OF FILING REBUTTAL TESTIMONY OF CARL N. STOVER, JR.**

Mohave Electric Cooperative, Inc. ("Mohave") by and through undersigned counsel, hereby submits the rebuttal testimony of Carl N. Stover, Jr.

DATED this 30th day of August, 2010.

Arizona Corporation Commission
DOCKETED
AUG 3 0 2010
DOCKETED BY

CURTIS, GOODWIN, SULLIVAN,
UDALL & SCHWAB, P.L.C.

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I hereby certify that on this 30th day of August, 2010, I caused the foregoing document to be served on the Arizona Corporation Commission by delivering the original and thirteen (13) copies of the above to:

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1234\-21\-2-1-10-1 (AEPCO 09 Rate Case - 09-0472)\Notice of Filing - Stover Surrebuttal Testimony 08-30-10.

BEFORE THE ARIZONA CORPORATION COMMISSION

IN THE MATTER OF THE APPLICATION OF THE ARIZONA ELECTRIC POWER COOPERATIVE, INC. FOR A HEARING TO DETERMINE THE FAIR VALUE OF ITS PROPERTY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RETURN THEREON AND TO APPROVE RATES DESIGNED TO DEVELOP SUCH RETURN	Docket No. E-01773A-09-0472

REBUTTAL TESTIMONY

OF

CARL N. STOVER, JR.

ON BEHALF

OF

MOHAVE ELECTRIC COOPERATIVE, INC.

August 30, 2010

REBUTTAL TESTIMONY OF
CARL N. STOVER, JR.
ON BEHALF OF
MOHAVE ELECTRIC COOPERATIVE, INC.

INTRODUCTION

Q. Please state your name and business address.

A. My name is Carl N. Stover, Jr.; my business address is 5555 North Grand Boulevard, Oklahoma City, Oklahoma 73112-5507.

Q. By whom are you employed and what is your position?

A. I am employed by C. H. Guernsey & Company, Engineers • Architects • Consultants. I am currently Chairman of the Board. My consulting activities include rate and financial analysis on behalf of our clients before state and regulatory commissions. I am also involved in long-range system planning, power supply planning, and development of power supply resources.

Q. Please briefly summarize your educational background and your professional experience.

A. I have a Bachelor of Science degree in Electrical Engineering and a Master of Science degree in Industrial Engineering. I am a Registered Professional Engineer, licensed in the states of Oklahoma, Kansas, Colorado, Wyoming, Iowa, and Texas. I am a member of the Power Engineering Society and the Engineering Management Society of the Institute of Electrical and Electronics Engineers.

Q. Have you previously appeared before state regulatory commission on matters related to cost of service, rate design and power supply planning?

A. Yes. I have appeared before regulatory commissions in the states of Arkansas, Colorado, Kansas, New Mexico, Oklahoma, Texas and Wyoming. Exhibit CNS-1 attached to this testimony is my resume.

Q. Have you published or presented papers concerning planning, rate design, cost of service, etc.?

A. Yes. *See* Exhibit CNS-1 for a listing of my papers and presentations.

Q. Have you testified before the Arizona Corporation Commission before?

A. I have submitted pre-filed surrebuttal testimony in Docket No. E-04100A-09-0496 related to Southwest Transmission Cooperative's rate filing.

Q. Upon whose behalf are you appearing in this proceeding?

A. I am appearing on behalf of Mohave Electric Cooperative, Inc. ("Mohave") an intervenor in this proceeding.

Q. Please describe your experience with Mohave Electric Cooperative, Inc.

A. I began working with Mohave in 2002. My work primarily relates to power supply-related activities including planning for power supply resources, integration of resources, and wholesale rates.

IMPACT OF AEPCO APPLICATION ON MOHAVE

Q. What is the relationship between Mohave and Arizona Electric Power Cooperative, Inc. ("AEPCO")?

A. Mohave is a Class A Member of AEPCO. As a Class A Member, Mohave has a representative on the AEPCO Board of Directors. AEPCO provides a portion of the wholesale power supply necessary to serve Mohave's retail load.

Q. How is Mohave impacted by the proposed AEPCO rate filing?

A. Table 1 below shows the rate impacts proposed by: 1) the AEPCO amended rate filing - 3.1% increase or $1,669,250, 2) Staff - 3.2% increase or $1,736,428, and 3) AEPCO rebuttal 2.37% increase or $1,284,126.

Table 1 – Rate Impact

	MWh	Present	Proposed	Increase	%
AEPCO Amended	-----------	-----------	-----------	-----------	-----------
Other Class A	1,729,084	112,413,132	110,647,129	(1,766,003)	-1.57%
Mohave	875,380	54,205,506	55,874,756	1,669,250	3.08%
Total Class A	2,604,464	166,618,638	166,521,885	(96,753)	-0.06%
Other Firm	68,952	3,879,531	3,879,531	-	0.00%
Other Non Firm		4,740,566	4,740,566		
Other Revenue		3,523,943	3,523,943		
Total AEPCO	2,673,416	178,762,678	178,665,925	(96,753)	-0.05%
Staff Proposed					
Other Class A	1,729,084	112,413,132	110,907,704	(1,505,428)	-1.34%
Mohave	875,380	54,205,506	55,941,934	1,736,428	3.20%
Total Class A	2,604,464	166,618,638	166,849,638	231,000	0.14%
Other Firm	68,952	3,879,531	3,879,531	-	0.00%
Other Non Firm		4,740,566	4,740,566		
Other Revenue		3,523,943	3,523,943		
Total AEPCO	2,673,416	178,762,678	178,993,678	231,000	0.13%
AEPCO Rebuttal					
Other Class A	1,729,084	112,413,132	109,956,689	(2,456,443)	-2.19%
Mohave	875,380	54,205,506	55,489,632	1,284,126	2.37%
Total Class A	2,604,464	166,618,638	165,446,321	(1,172,317)	-0.70%
Other Firm	68,952	3,879,531	3,879,531	-	0.00%
Other Non Firm		4,740,566	4,740,566		
Other Revenue		3,523,943	3,523,943		
Total AEPCO	2,673,416	178,762,678	177,590,361	(1,172,317)	-0.66%

SUMMARY OF TESTIMONY

Q. What is the purpose of your testimony in the proceeding?

A. I am offering rebuttal testimony for the following purposes:

1. To support AEPCO's proposed net margin of $4,059,576 based upon a 1.32 Debt Service Coverage ("DSC") and a revenue decrease of $1,172,317 as set forth in Mr. Pierson's Rebuttal Testimony and summarized on his Exhibit GEP-2.

2. To explain why the Commission should reject ACC Staff's ("Staff") proposed net margin of $5,462,907 based on a 1.40 DSC for a revenue increase of $231,000.

3. To support approval of the amended Partial-Requirements Capacity and Energy Agreements between AEPCO and Mohave and between AEPCO and Sulphur

Springs Valley Electric Cooperative, as well as the new Partial-Requirements Capacity and Energy Agreements between AEPCO and TRICO Electric Cooperative.

Table 2 summarizes the DSC and associated net margins and cash from operations as proposed in the AEPCO amended filing, ACC Staff proposal, and AEPCO rebuttal testimony. Staff is proposing an increase in margins from the AEPCO Amended filing of $2.2 million or approximately 69%. The AEPCO rebuttal proposal increases AEPCO's net margin and cash after debt service approximately $800,000 more than the AEPCO Amended filing.

Table 2 – DSC, Net Margins, and Cash After Debt Service

			(A)	(B)	(C)
			AEPCO	Staff	AEPCO
		Reference	Filed	Proposed	Rebuttal
		--------------	-----------	-----------	-----------
1	Net Margin		$ 3,236,591	$ 5,462,907	$ 4,059,575
2	Plus: Interest	RCS-2, Line17	$ 10,812,194	$ 10,812,194	$ 10,812,194
3	Plus: Depreciation	RCS-2, Line 18	$ 8,348,168	$ 8,317,632	$ 8,317,632
4	Cash Before Debt Service	L1 + L2 + L3	$ 22,396,953	$ 24,592,733	$ 23,189,401
5	Debt Service	L11	$ (17,566,238)	$ (17,566,238)	$ (17,566,238)
6	Cash After Debt Service	L4 + L5	$ 4,830,715	$ 7,026,495	$ 5,623,163
7	DSC	L 4/L11	1.275	1.400	1.320
8	TIER	(L1+L2)/L2	1.299	1.505	1.375
	Debt Service				
9	Principal	RCS-2, Line 21	$ 6,754,044	$ 6,754,044	$ 6,754,044
10	Interest	RCS-2, Line 20	$ 10,812,194	$ 10,812,194	$ 10,812,194
11	Total	L9 + L10	$ 17,566,238	$ 17,566,238	$ 17,566,238

MOHAVE SUPPORTS AEPCO'S REBUTTAL POSITION ON THE LEVEL OF RATE INCREASE

Q. Does Mohave Electric Cooperative support the $1,172,317 decrease in annual revenues requested by AEPCO in its Rebuttal Testimony?

A. Yes.

Q. Do you believe the proposed net margin of $4,059,575 requested by AEPCO, the associated cash from operations after debt service of $5,623,163, and the resulting 1.32 DSC is appropriate.

A. Yes. I believe a DSC of 1.32 is adequate for AEPCO.

Q. Why do you believe it is adequate?

A. The appropriate level of DSC is defined by the margin and cash flow from operations that will allow the Generation and Transmission Cooperative ("G&T") to meet its equity objective, cash reserve objective, and capital credit refund objective, given the projected capital requirements. In order to provide a common basis for evaluation I used some of the factors considered by Staff witness Randall Vickroy but with some modifications that reflect conditions specific to AEPCO.

Q. What are the factors that are unique to AEPCO that need to be considered?

A. First with regard to equity, AEPCO equity as a percentage of capitalization was 29.45% as of 12/31/2009. The rating analysis that Mr. Vickroy references indicates that an equity of between 20% and 35% reflects an A rating which is certainly investment grade. So I believe AEPCO has realized a satisfactory equity level.

With regard to capital credit refunds, AEPCO is not making any capital credit payments to Members so there is no margin requirement to meet a capital credit refund objective.

With regard to capital requirements AEPCO is in a unique situation relative to the typical (G&T). The typical G&T has an obligation to serve future Member load. This means the G&T must provide resource additions to serve load. This mean the G&T must maintain sufficient financial ratios to access capital markets to obtain capital to finance generation resources necessary to serve future Member load growth. On a going forward basis AEPCO has a much lesser requirement to access capital to finance generation additions to serve future Member load growth since approximately 90% of the AEPCO sales to Class A Members are to Partial Requirement Members (PRM). Under the existing agreements, each PRM has an obligation to find resources to serve load growth.

Another consideration is that AEPCO has no risk uncertainty with regard to future revenue stream. The proposed rate design which has been supported by all parties, including Staff, provides AEPCO certainty with regard to recovery of fixed costs associated with providing service. The future revenue required to recover fixed cost is not dependent on usage. Only those costs that vary as a function of energy usage will be recovered on energy billing units. To provide even more certainty, a significant portion AEPCO's cost (fuel, purchased power fixed and variable cost) and revenue credits (associated with third party sales) are subject to a Fuel and Purchase Power Cost Adjustor (FPPCA) that allows AEPCO to periodically reconcile for changes from the base value reflected in the rates. This does not mean that AEPCO can ignore cost containment issues. A significant portion of AEPCO's fixed costs (such as wages) are not subject to automatic reconciliation and increases in energy sales will not collect any portion of these fixed costs. Therefore, it will be imperative that AEPCO control costs.

With regard to meeting coverage objectives, AEPCO has a requirement to maintain a 1.0 DSC to meet RUS mortgage obligations (Reference Direct Testimony of Randall Vickroy Page 3, Line 17). In the last rate case the Commission approved a 1.13 DSC. Staff testimony indicates a 1.25 DSC is sufficient for investment grade rating. *See* Vickroy Direct at 12, line 22 -13, line 14 and 15, lines 8 - 11. A 1.32 DSC would provide for adjustments to reflect other factors in the rating valuation process.

The final consideration is the ability to maintain cash reserves. The ability to realize necessary cash reserves should be enhanced with a 1.32 DSC because this means cash flow from operation will actually be approximately $800,000 greater than the AEPCO Amended proposal.

STAFF'S PROPOSED NET MARGIN AND DSC RESULTS IN AN UNREASONABLE AND UNNECESSARY RATE INCREASE

Q. Why do you believe the proposed Staff recommendation of a 1.40 DSC is inappropriate?

A. Mr. Vickroy determines a 1.25 DSC could be appropriate to maintain investment grade rating based on the Financial Metrics criteria. *See* Vickroy Direct at 12, line 22 through 13, line 14. He then develops a range of 1.25 - 1.45 as being reasonable. *Id.* at 15, line 8. He never describes why the 1.45 is the appropriate upper bound. However, he then develops adjustments related to qualitative factors which results in his concluding that a 1.40 DSC is within his defined range and is appropriate. I believe his adjustments are excessive and not supported by the data presented in this proceeding. I believe that appropriate consideration of the qualitative factors that he applies would result in the conclusion that a 1.32 DSC is adequate.

Q. Please provide more detail as to how Mr. Vickroy develops his recommended 1.40 DSC?

A. He states that he evaluated AEPCO's "...coverage requirements based on risk evaluation techniques used by the credit rating agencies." *See* Vickroy Direct at 8, lines 10 - 11. He states that using both quantitative criteria and qualitative criteria he established a range of DSC ratios. He then considered "...AEPCO's current prospects (as indicated by its projected capital expenditure program, cash situation, other contingencies)..." to develop a recommended DSC level and its commensurate cash flow within the range. *See* Vickroy Direct at 8, line 24 through 9, line 2.

Q. Does Mr. Vickroy identify the specific criteria that will be used in his analysis?

A. Yes. He provides not only the criteria but also the weighting that should be given to each criteria. They are:

1. Financial Performance and Metrics (40%)
2. Long-term Wholesale Power Supply Contracts / Regulatory Status (20%)
3. Rate Flexibility (20%)
4. Member Profile (10%)
5. Size (10%)

Q. What is the source of the criteria and the weighting factors used by Mr. Vickroy?

A. Mr. Vickroy does not provide a specific reference; however, the criteria and weighting factors can be found in a rating methodology report published by Moody's Investment Services for U.S. Electric Generation & Transmission Cooperatives, published in December 2009. A copy is attached as Exhibit CNS-2.

Q. Please describe Mr. Vickroy's general process in developing his recommendation.

A. He begins with an analysis based on the Financial Performance and Metrics. He states that, "The rating mid-point DSC coverage, for instance, is 1.25, as compared to the company's request of 1.275. Based solely upon the quantitative metrics, AEPCO's rate request could produce financial results that would qualify the Cooperative for an investment-grade credit rating in either the Baa or A categories." *See* Vickroy Direct at 13, lines 11 - 14. He states that, "However, we have yet to account for numerous qualitative factors and AEPCO business factors that can influence these quantitative results upward or downward." (*See* Randall Vickroy's Direct Testimony Page 13, line 14). After accounting for the qualitative results the 1.25 DSC value is adjusted upward to a DSC of 1.40.

Q. Please describe Mr. Vickroy's assessment of the qualitative factors and specific factors that caused him to increase the DSC from 1.25 to 1.40.

A. Table 3 summarizes the criteria, Mr. Vickroy's assessment of criteria in terms of impact on rating level, and specific references to his testimony. There are actually ten criteria considered in both the Moody's report and Mr. Vickroy's testimony in addition to the criteria related to Financial Metrics.

Table 3 – Criteria Referenced by Vickroy

Ref	*Criteria*	*Impact*	*Testimony Ref*
2a	Long Term Contracts	Positive	P14, L 3
2b	Regulatory Status	Negative	P14, L5
3a	Rate Flexibility: Board involvement/Rate Adjustment Mechanisms	Baa	P14, L12
3b	Rate Flexibility: New construction build exposure	Baa	P14, L12
3c	Rate Flexibility: Competitiveness	Baa – Ba	P14, L13
3d	Rate Flexibility: Purchased Power Percentage	Positive	P14, L15
4a	Member Profile: Percentage of Retail Sales	Positive	P14, L17
4b	Member Profile: Member Capitalization	Baa	P14, L19
5a	Size: Energy Sales	Negative	P14, L21
5b	Size: Net Plant	Negative	P14, L21

Mr. Vickroy summarizes his analysis by stating, "The nonfinancial rating factors evaluated here indicate that AEPCO carries significant levels of added risk due to its regulatory status, rate flexibility criteria, and small sales and asset bases." (*See* page 15, line 1.) He apparently makes his upward adjustment based on criteria 2b, 3c, 5a, and 5b.

Q. **There are a total of ten criteria to consider. He identifies four as having a negative impact. Does he appear to consider factors that have a positive impact?**

A. I could not find any reference in his testimony to how he might have weighted the factors with a positive impact as offsets to the four factors that have a negative impact.

Q. **Do you have comments related to evaluation of the four qualitative factors that Mr. Vickroy uses to justify the increase the DSC requirement?**

A. Yes. Let me begin with Regulatory Status criteria. Mr. Vickroy makes the general statement that Moody's considers being rate regulated as a negative factor for purposes of ratings. (*See* Vickroy Direct at 14, line 5.) The fact is that based on Moody's analysis an entity that is rate regulated can qualify for an A rating. *See* CNS-2 at 8, Factor 1 Chart.

Rather than regulation resulting in a rating below investment grade, the issue appears to be how the regulatory commission deals with the cooperative. In order to qualify for a below-investment grade rating, the environment for a Ba rating the regulatory condition as defined by Moody's would be "Unsupportive Commission Practices, Generally Difficult Regulatory Relationships" or for a B rating "Very Unsupportive Commission Practices; Often Contentious Regulatory Relationships." *See* CNS-2 at 8, Factor 1 Chart. Mr. Vickroy does not indicate why he views the ACC regulatory condition as having a negative impact. It is interesting to note that even with a negative rating for regulation, his evaluation of contract status and regulatory status results in a Baa category. *See* Vickroy Direct at 14, lines 4 – 8.

Q. How do you view the relationship between the ACC and AEPCO?

A. This is my first opportunity to testify before the ACC so I have no personal experience. I can reference what has actually happened to AEPCO under ACC rate regulation. The current rates paid by the AEPCO Class A Members became effective with the first phase in 9/2005, the second phase in 9/2006, and the third phase in 9/2007. Given the rate the ACC approved (reference Exhibit LCG -2):

1. The financial ratios have improved significantly from a 12/31/2003 value:
   a. Equity increased from 4.77% to 29.45%
   b. DSC increased from 0.56 to 1.70
2. The ACC also approved a flow through provision that allows flow through (subject to ACC approval) of:
   a. All changes in fuel cost
   b. All changes in purchased power cost
   c. All changes in transmission cost associated with purchased power
   d. All changes in impact related to sales to third parties

The ACC regulatory actions have resulted in AEPCO realizing a significant improvement in financial ratios under the rates last approved by the ACC. Even more importantly the ACC allows AEPCO full recovery of changes (either increase or decrease) of a major component of cost of service. The adjuster even allows for recovery of any changes (reduced margins) associated with third-party sales. It would not appear that ACC regulation has had an adverse impact on AEPCO's ability to recover cost and improve earnings.

Therefore, I believe that Mr. Vickroy has overstated the negative impact of regulation in general. Based on actual financial performance, it also appears that he has overstated the specific impact on AEPCO of ACC regulation. I am not sure what has caused him to classify the ACC/AEPCO relations as Unsupportive Commission, Generally Difficult Regulatory Relationships, or Very Unsupportive Commission Practices, Often Contentious Regulatory Relationships.

Q. What are your comments related to rate Flexibility Criteria?

A. There are four subcomponents under this classification and three of these are given investment grade status or a positive rating by Mr. Vickroy. His negativity relates to competitiveness. *See* Vickroy Direct at 14, lines 13 – 14.

In reviewing the Moody's analysis there is a criterion for a "Potential for Rate Shock Exposure." Moody's indicates that the potential for rate shock exposure is linked to rate competitiveness so they combined the two. *See* CSN-2 at 8. There appears to be two issues this criterion addresses:

1. A G&T may have very competitive rates but be exposed to a substantial rate shock because of rate increase.
2. A G&T could have higher rates than other providers in the area.

Mr. Vickroy is not clear as to how he is applying these criteria. He has not provided any comparison of AEPCO rates with other suppliers in the area. Even given the ACC Staff proposal resulting in a rate increase of 0.14%, there is no suggestion of major rate shock. Therefore, there does not seem to be any support for suggesting a negative rating for these criteria.

Q. The third criterion supporting an increase in DSC is related to size. Do you agree with Mr. Vickroy's adjustment for this criterion?

A. No. Again, referencing the Moody's report related to G&T size the report states, "Size, together with Factor 3 Member Profile, has the lowest weighting of the five key factors because it tends to be less important for entities, such as G&T coops, that are subject to limited competition." *See* CSN-2 at 14. The report again goes on to say that size does matter in that the greater number of energy sales the greater the base over which to spread cost, and the greater the size the greater the opportunities for a large pool of diversified assets and diversity of fuel resources.

AEPCO is small compared to other G&Ts. However, I think it is important to note that with diversity as a major objective, AEPCO has been able to achieve diversity of fuel with a portfolio of coal, gas, and hydro which provides a great deal of fuel diversity benefits to its Members. In addition, AEPCO has a mix of owned and purchased power assets in place to serve its Members. Therefore, certain of the factors that large size is intended to capture in the Moody methodology, I believe AEPCO has been able to capture even with their relative small size.

Q. Are there other factors that are specific to AEPCO that you believe need to be considered in establishing the appropriate DSC level?

A. Yes. The conditions that typically relate to a G&T are:

1. The G&T has an obligation to provide power supply resources to serve the Member's retail load.
2. The G&T obligation is to assume the volume risk and be responsible to serve the Member load whatever the load might be.
3. Because of the obligation to serve Member load, the G&T must make sure it has access to capital necessary to finance the asset additions required to serve load.
4. Therefore, the G&T must:
    a. If a G&T can finance through RUS/FFB/CFC/CoBank, maintain adequate financial ratios to meet debt indenture requirement.
    b. If a G&T must go to the markets to finance, maintain adequate financial ratios to access the markets at favorable interest rates which means maintaining investment grade ratings.

AEPCO, unlike most other G&T's:

1. Does not have responsibility to serve all of the Member retail load growth.
2. Does not have volume risk uncertainty for a large portion of Member load.

This is because approximately 90% of the Class A Member load will be served under a PRM service obligation (Mohave, TRICO, SSVEC). AEPCO does not have a contractual obligation to access capital markets for major capital additions to serve load growth associated with these three Members. In addition, a PRM service agreement eliminates AEPCO's volume risk uncertainty associated with changes in existing retail load for these members.

Q. Are there any other factors that should be considered?

A. Yes, in the last rate case in Docket No. E-01773A-04-0528 the Commission determined that a DSC of 1.13 was appropriate. The Commission determined this was appropriate given a G&T with the equity of approximately 5%. ACC Staff is now suggesting a 1.40 DSC with an equity of approximately 30%.

Q. Does Mr. Vickroy have any other justifications for his proposed 1.40 DSC?

A. Yes. He indicates that he believes the $3.2 million margin and $4.8 million cash from operations as proposed by AEPCO is too thin from a cash flow perspective and would provide little cushion to cover unexpected operating problems and contingencies. *See* Vickroy Direct at page 16, lines 12 - 16. Mr. Vickroy apparently believes that approximately $2.2 million should be added to the revenue requirement to account for future events that are not reflected in the test year. He is using the margin component of the revenue requirement to provide a cushion to deal with future speculative contingencies.

Q. Does Mr. Vickroy have any comment about cash situation on a going forward basis?

A. Yes. He states "I do not believe, however, that the cash situation is quite so dire on a going forward basis." *See* Vickroy Direct at 16, line 23.

Q. What are your conclusions with regard to the basis for Mr. Vickroy's recommendation of a 1.40 DSC?

A. His justification for adjustment from 1.25 to 1.40 appears to be based on four criteria that he views as a basis for the upward adjustment. He does not consider the other six criteria as providing any positive pressures that could offset the upward adjustment. Of the four factors he does not provide any basis for the negative view of competitiveness criteria. There is clearly no basis in terms of a rate shock and no evidence presented that AEPCO wholesale rates are not competitive with other wholesale rates offered for similar service. With regard to the size criterion, I believe that AEPCO has been able to realize the diversity attributes (fuel and ownership) typically assumed to drive this criterion. This leaves the negative adjustment related to ACC regulation of AEPCO. As I have indicated, actual experience does not seem to suggest that regulation has had an adverse impact on AEPCO sufficient to justify the DSC adjustment Mr. Vickroy is proposing. In fact Mr. Vickroy indicates that the contract and regulatory criteria combined result in an investment grade rating. I believe that AEPCO's proposed DSC of 1.32 is sufficient. It produces a margin of $4,059,575 and a cash flow from operations of $5,623,163.

<u>SHOULD THE COMMISSION APPROVE THE AMENDED AND NEW PARTIAL-REQUIREMENTS CAPACITY AND ENERGY AGREEMENTS</u>

Q. On June 2, 2010, AEPCO, Mohave, SSVEC and TRICO filed a Joint Request for Contract/Amendments Approvals and Revised Rates Request. Please briefly explain the nature of that filing.

A. For the past four years, AEPCO and its members have been involved in sometimes heated negotiations over the allocation of costs. Last year TRICO gave notice that it was converting from an all to a partial requirements member. The Amendments with the Mohave and SSVEC agreements, the new Partial-Requirements Capacity and Energy Agreement with TRICO, as well as the amendments to the all-requirements Wholesale Power contracts between AEPCO and Duncan Valley Electric Cooperative, Inc. and AEPCO and the Graham County Electric Cooperative, Inc. collectively implement agreed upon changes to the cost allocation and rate design. These changes are reflected in the rates now being proposed by AEPCO in this docket. The amendments and new contract resolve disputes that arose under existing agreements and have substantially reduced the issues that would have been raised in connection with AEPCO's initial filing.

Q. Why should the Commission approve the amendments and the contract?

A. The agreements benefit the Parties and the public by providing for a fair, equitable and repeatable allocation of costs and revenues between the PRMs and ARMS based on principles of cost causation, while providing AEPCO with fair and reasonable recovery of its revenue requirements and sufficient operating margins.

Q. Do you reserve comment on other aspects of AEPCO's rebuttal testimony?

A. Yes. Neither Mohave nor I have seen the rebuttal testimony being filed by AEPCO simultaneously with my rebuttal testimony. Therefore, except to the extent specifically adopted and supported in my testimony, Mohave and I expressly reserve the right to comment thereon in rejoinder testimony or at hearing.

Q. Does this conclude your testimony?

A. Yes, it does.

EXHIBIT CNS-1

EDUCATION:

M.S., Industrial Engineering, The University of Oklahoma, 1969
B.S., Electrical Engineering, The University of Oklahoma, 1963
Stanford University School of Business Administration, "Leading Change and Organizational Renewal," Summer 2001.
Harvard Business School Executive Education, "What's Next & So What? - Leading in the 21st Century," January 2000.
Harvard Graduate School of Business Administration, "Leadership in Professional Service Firms," June 1995.

REGISTRATIONS:

Professional Engineer: Colorado - 12931, Iowa - 11754, Kansas - 6261, Oklahoma - 8526, Texas - 67676, Wyoming - 1215

PROFESSIONAL ACTIVITIES / HONORS:

Associate Member, National Rural Electric Cooperative Association, 1998 - Present
Associate Member, American Public Power Association, 1997 - Present
Member, College of Engineering Board of Visitors, The University of Oklahoma, 1989 - Present
Member, Chairman; Electric Power Advisory Board, School of Electrical Engineering and Computer Science, The University of Oklahoma, 1985 - Present
Member, Institute of Electrical and Electronics Engineers, 1970 – Present
Distinguished Graduates Society Inductee, College of Engineering, The University of Oklahoma, 1998

EXPERIENCE RECORD:

1966 - Present **C. H. Guernsey & Company, Oklahoma City, Okla.**

2005-Present, Chairman of the Board
1990-2005, Chairman of the Board, CEO and President
1989-1990, President, Board of Directors
1980-1989, Executive Vice President, Board of Directors
1972-1980, Vice President, Board of Directors

Mr. Stover's primary areas of responsibility include preparation of retail and wholesale rate analysis for regulated and unregulated systems, strategic planning, financial analysis and forecasting, resource planning and power supply negotiations, and training for utility clients. Mr. Stover has appeared before the Arkansas, Colorado, Kansas, Oklahoma, Texas, Utah and Wyoming state commissions, as well as the Federal Energy Regulatory Commission.

1963 - 1966 **USAF.** Assigned to Inertial Guidance Laboratory at Holloman AFB, New Mexico.

Lt. Stover served as engineer in testing and evaluation of inertial guidance systems, and received an honorable discharge as 1st Lieutenant.

SPECIFIC CONSULTING EXPERIENCE:

Rate Proceedings – Distribution Cooperatives

Arkansas (Arkansas Public Service Commission)

- Ozarks Electric Cooperative Corporation, Fayetteville (Docket 86-162-U)

COLORADO (Colorado Public Utilities Commission)

- Delta-Montrose Electric Association, Delta
- Empire Electric Association, Inc., Cortez
- Gunnison County Electric Association, Inc., Gunnison
- Holy Cross Electric Association, Inc., Glenwood Springs
- Intermountain Rural Electric Association, Sedalia
- La Plata Electric Association, Inc., Durango
- Moon Lake Electric Association, Inc., Roosevelt, UT
- Poudre Valley Rural Electric Association, Inc., Ft. Collins
- San Isabel Electric Association, Inc., Pueblo
- San Luis Valley Rural Electric Cooperative, Inc., Monte Vista
- San Miguel Power Association, Inc., Nucla
- United Power, Inc., Brighton
- White River Electric Association, Inc., Meeker

Illinois

- Egyptian Electric Cooperative Association, Steeleville
- SouthEastern Illinois Electric Cooperative, Inc., Eldorado
- Southern Illinois Electric Cooperative, Dongola

Indiana (Indiana Public Service Commission)

- Clark County Rural Electric Membership Corporation, Sellersburg

Kansas (Kansas Corporation Commission)

- Ark Valley Electric Cooperative Association, Inc., Hutchinson
- C.M.S. Electric Cooperative, Inc., Meade
- D.S.&O. Rural Electric Cooperative Association, Inc., Solomon
- Lane-Scott Electric Cooperative, Inc., Dighton
- Ninnescah Rural Electric Cooperative Association, Inc., Pratt
- Sedgwick County Electric Cooperative Association, Inc., Cheney
- Sumner-Cowley Electric Cooperative, Inc., Wellington
- Victory Electric Cooperative Association, Inc., Dodge City
- Western Cooperative Electric Association, Inc., WaKeeney

Nebraska

- McCook Public Power District, McCook
- Panhandle Rural Electric Membership Corporation, Alliance
- Twin Valleys Public Power District, Cambridge

Oklahoma (Oklahoma Corporation Commission)

- Caddo Electric Cooperative, Binger
- Canadian Valley Electric Cooperative, Seminole
- Central Rural Electric Cooperative, Stillwater
- Cimarron Electric Cooperative, Kingfisher
- Cookson Hills Electric Cooperative, Inc., Stigler
- Cotton Electric Cooperative, Walters
- East Central Oklahoma Electric Cooperative, Inc., Okmulgee
- Harmon Electric Association, Inc., Hollis
- Indian Electric Cooperative, Inc., Cleveland
- Kay Electric Cooperative, Blackwell
- Kiwash Electric Cooperative, Inc., Cordell
- Lake Region Electric Cooperative, Inc., Hulbert
- Northeast Oklahoma Electric Cooperative, Inc., Vinita
- Northfork Electric Cooperative, Sayre
- Northwestern Electric Cooperative, Inc., Woodward
- Oklahoma Electric Cooperative, Norman
- Oklahoma Gas & Electric Company, Cause No. 29450
- People's Electric Cooperative, Ada
- Red River Valley Rural Electric Association, Marietta
- Rural Electric Cooperative, Inc., Lindsay
- Southwest Rural Electric Association, Inc., Tipton
- Sun Oil vs. Arkansas Louisiana Gas Company
- Verdigris Valley Electric Cooperative, Inc., Collinsville

South Dakota

- West Central Electric Cooperative, Inc., Murdo

Texas (Public Utility Commission of Texas)

- Bailey County Electric Cooperative Association (2915, 5003, 7900)
- Bandera Electric Cooperative, Inc. (2786, 4279)
- Bluebonnet Electric Cooperative, Inc. (266, 4070, 7415, 12126)
- Central Texas Electric Cooperative, Inc. (3170, 6363, 7661, 10325, 12127)
- Cherokee County Electric Cooperative Association (817)
- City of Austin (6560 - in behalf of Bergstrom AFB
- Coleman County Electric Cooperative, Inc. (4875, 13335)
- Comanche County Electric Cooperative, Inc. (5272, 8272)
- Concho Valley Electric Cooperative, Inc. (3550, 4797, 6540, 9056, 13334)
- Cooke County Electric Cooperative Association (9240)
- CoServ Electric (3470, 4189, 5165, 9892, 21669)

- Deaf Smith Electric Cooperative, Inc. (4481, 5019, 8354)
- Department of Defense (Bergstrom AFB v. City of Austin (6560)
- Fannin County Electric Cooperative, Inc. (3747, 4940, 9992)
- Farmers Electric Cooperative, Inc. (3780, 4422, 5259, 6475)
- Fort Belknap Electric Cooperative, Inc. (4396, 6558, 9944)
- Grayson-Collin Electric Cooperative, Inc. (3945, 6510)
- Greenbelt Electric Cooperative, Inc. (5038, 9930, 10405)
- Guadalupe Valley Electric Cooperative, Inc. (398, 3397, 4516, 6338, 7550)
- Hamilton County Electric Cooperative Association (5971)
- HILCO Electric Cooperative, Inc. (7154)
- Houston Lighting and Power Company (5779 and 8425)
- Jackson Electric Cooperative, Inc. (2753, 4710, 10561)
- Lamb County Electric Cooperative, Inc. (3270)
- Lighthouse Electric Cooperative, Inc. (2995, 4612, 8097)
- Lyntegar Electric Cooperative, Inc. (2988, 4564)
- Magic Valley Electric Cooperative, Inc. (1991, 3212, 5477, 20281, 20314)
- Medina Electric Cooperative, Inc. (4113, 11048)
- Big County Electric Cooperative (formerly Midwest) (2717, 3711, 6983)
- Navarro County Electric Cooperative, Inc. (3116)
- Navasota Valley Electric Cooperative, Inc. (7355)
- North Plains Electric Cooperative, Inc. (2934, 4958, 5214)
- Nueces Electric Cooperative, Inc. (3936, 5203, 23454)
- Pedernales Electric Cooperative, Inc. (2247, 3437, 5109)
- Rio Grande Electric Cooperative, Inc. (521, 3681)
- Rita Blanca Electric Cooperative, Inc. (2527, 8422)
- Rusk County Electric Cooperative, Inc. (3383)
- San Bernard Electric Cooperative, Inc. (2699, 3692, 4534, 5467, 6218)
- South Plains Electric Cooperative, Inc. (2936, 4822, 6985)
- Southwest Texas Electric Cooperative, Inc. (5335)
- Swisher Electric Cooperative, Inc. (3062, 6796)
- Taylor Electric Cooperative, Inc. (3679, 5767, 9159)
- Victoria Electric Cooperative Company (770, 3949, 6680)
- Wharton County Electric Cooperative, Inc. (4541, 6685)

Utah (Utah Public Service Commission)

- Empire Electric Association, Inc., Cortez, Colo.
- Moon Lake Electric Association, Inc., Roosevelt

Wyoming (Wyoming Public Service Commission)

- Big Horn Rural Electric Company (9076)
- Bridger Valley Electric Association, Inc. (9447)
- Carbon Power & Light, Inc. (9022)
- Garland Power & Light, Inc. (9575)
- High Plains Power
- Niobrara Electric Association, Inc. (9572)
- Wheatland Rural Electric Association (9574)

- Wyrulec Company (9097)

Rate Proceedings - Municipal Utilities

- Altus, Okla.
- AWC of LCRA, Texas
- Blackwell, Okla.
- Braman, Okla.
- Bryan, Texas
- Chanute, Kans.
- Chatham, Ill.
- Cody, Wyo.
- Cushing, Okla.
- Fredericksburg, Texas (7661, Certification - Central Texas EC)
- Lamar, Mo. vs. SWPA
- Larned, Kans.
- New Braunfels Utilities, Texas
- Oklahoma Municipal Power Authority, Okla.
- Osborne, Kans.
- Piedmont Municipal Power Authority, S. Car.
- Ponca City, Okla.
- Raton, N. Mex.
- Riverton, Ill.
- Stillwater, Okla.
- Torrington, Wyo.
- Vernon, Texas
- Wellington, Kans.

Rate Proceedings - Wholesale

Arkansas (Arkansas Public Service Commission)

- Arkansas Electric Cooperative Corporation Docket Nos. U-3071, 83-023-U

Colorado

- Tri-State G&T Association, Inc. Docket No. 98A-511E

Illinois

- Southern Illinois Power Cooperative

Iowa

- Corn Belt Power Cooperative, Inc.
- Northwest Iowa Power Cooperative, Inc.

Kansas

- Kansas Electric Power Cooperative, Inc.

Louisiana

- Cajun Electric Power Cooperative, Inc. Docket No. U-17735

Minnesota

- Great River Energy

Missouri

- M & A Electric Power Cooperative

New Mexico

- Plains Electric G&T Cooperative, Inc. Merger with Tri-State G&T Assn.

Nebraska

- Nebraska Electric G&T Cooperative, Inc., Columbus

North Carolina

- North Carolina Electric Membership Corporation

North Dakota

- Basin Electric Cooperative, Inc.
- Central Power Electric Cooperative, Inc.

South Dakota

- Rushmore Electric Power Cooperative, Inc.

Texas (Public Utility Commission)

- Brazos Electric Cooperative Docket Nos. 4079, 8868, 12757, 13100, 22531
- Central and South West Corp. / American Electric Power Company Docket No. 19265
- Golden Spread Electric Cooperative Docket Nos. 13444, 14980, 15100, 16738
- Lower Colorado River Authority Docket Nos. 366, 1521, 2503, 3522, 3838, 6027, 7512, 8032, 8400, 9427
- Rayburn Country Electric Cooperative Docket No. 7361
- San Miguel Electric Cooperative, Inc. Docket No. 4127, 5351
- South Texas Electric Cooperative, Inc. Docket Nos. 4128, 5077, 5387, 5440, 8952, 22344
- Southwestern Electric Service Company Docket No. 2817
- Southwestern Public Service Company Docket Nos. 4387, 6055
- Texas Electric Service Company Docket Nos. 527, 1903, 2606, 3250, 4097, 5200
- Texas Power & Light Company Docket Nos. 3006, 3780, 4321
- Texas Utilities Electric Company Docket Nos. 5640, 9300, 13100
- Texland Electric Cooperative, Inc. Docket No. 3896
- West Texas Utilities Company Docket No. 4716

Utah

- Deseret G&T Cooperative, Inc. Docket No. OA97-3-000; Docket No. 98-2035-04 PacifiCorp / ScottishPower Merger

Rate Proceedings - Federal Power Commission (Federal Energy Regulatory Commission)

- Cajun Electric Power Cooperative vs. Gulf States Utilities Company Docket Nos. EL87-051, ER88-477

- Central and South West Services — Docket No. ER84-031
- Central Power & Light Company — Docket Nos. ER77-331, ER81-387, ER86-721
- El Paso Electric Company — Docket Nos. ER76-409, ER77-488, ER79-526, ER81-426, ER84-236, ER86-368
- Golden Spread Electric Cooperative — Docket Nos. ER87-396, EL89-050 EL95-24
- Oklahoma Gas & Electric Company — Docket Nos. ER77-127, ER77-215, ER78-423, ER80-421, ER82-256, ER84-541
- Public Service Company Colorado — Docket Nos. ER76-381, ER76-687, ER78-507, ER80-407
- Public Service Company Oklahoma — Docket Nos. ER77-422, ER78-511, ER82-545
- Southwestern Public Service Co. — Docket Nos. ER84-604, ER85-477, EL89-051
- West Texas Utilities Company — Docket Nos. ER80-038, ER82-023, ER82-708, ER83-694, ER84-236, ER85-081, ER87-065

Transmission Wheeling / Interconnection Analysis

- Central and South West Services, Inc. — Docket No. EL79-008, ER82-545, et.al.
- LCRA Wheeling Case before the Texas PUC — Docket No. 6995

Power Supply Planning

A. System Resource Planning:

- Golden Spread Electric Cooperative, Inc.: Notice of Intent (PUCT Docket No. 13444)
- Golden Spread Electric Cooperative, Inc.: Exempt Wholesale Generation Contract Certification (PUCT Docket No. 15100)
- Holy Cross Energy and Yampa Valley Electric Association, Colorado
- South Texas Electric Cooperative, Texas

B. Long-Range Power Cost - 20-Year Forecast:

- Golden Spread Electric Cooperative, Inc. — Southwestern Public Service Company
- Mid-Tex G&T Electric Cooperative, Inc. — West Texas Utilities Company and Brazos Electric Cooperative
- Magic Valley Electric Coop., Inc. — South Texas Electric Coop., Inc.
- Rio Grande Electric Cooperative, Inc. — Central Power & Light Company
- Magic Valley Electric Cooperative, Inc. — City of Brownsville/Central Power & Light Co.

C. Other Power Supply Planning Projects:

- Golden Spread Electric Cooperative, Inc., TX — Mustang Station
- Magic Valley Electric Cooperative, Inc., TX — Magic Valley Station

Training

Training - NRECA

"Financial Planning and Strategies Workshop," presented for NRECA's Management Internship Program, Madison, Wisconsin; Yearly in May: 2005, 2006, and 2007.

"Financial Strategy and Rate Design for a Competitive World," presented for NRECA's Financial Planning and Strategies Workshop; Lincoln, Nebraska; Yearly in May: 2000, 2001, 2002 and 2004.

"Rate Design in a Restructured Environment," presented for NRECA's Management Internship Program; Lincoln, Nebraska; Yearly: 1999-2001.

"Financial Strategy and Rate Issues for the Changing Utility Industry," NRECA's Advanced Financial Planning; Lincoln, Nebraska; 1997-99.

"Rate Issues and Strategy for the Changing Utility Industry," NRECA's Management Internship Program; Lincoln, Nebr., 1987-98.

"Identifying Revenues and Costs Associated with Marketing Solutions," NRECA's Strategic Marketing Planning for Management Conference; Lincoln, Nebr., 1996-97.

"Application of Market-Based Rates in a Competitive Utility Industry," presented to NRECA's Tech Advantage '97 Annual Meeting; Las Vegas, Nevada; March 15, 1997.

"Rate Analysis," NRECA MIP Advanced Planning and Analysis Workshop; Lincoln, Nebr.; 1990-96.

"Power Supply Issues in the U.S. and Abroad - Increasing Competition and Deregulation," for Management and Technical Issues Conference for International Guests at 1996 NRECA Annual Meeting; Houston, Texas; March 23, 1996.

"Rates and Related Issues," for Management and Technical Issues Conference for International Guests at 1996 NRECA Annual Meeting; Houston, Texas; March 23, 1996.

"Rate Issues and Philosophies," NRECA's Management Internship Program; Lincoln, Nebr.; 1986-96.

"Competitive Strategies: The Economics of Serving Large Loads," NRECA's Summer School; New Orleans, La., June 30-August 1, and Hilton Head, S.C., July 18-19, 1995.

"Competitive Strategies: The Economics of Serving Large Loads," NRECA G&T Rates Conference; Lincoln, Nebr., June 20-21, 1995.

"Competitive Strategies: The Economics of Serving Large Loads," NRECA G&T Rates Conference; Lincoln, Nebr., June 14-15, 1994.

"Competing in the '90s and Beyond," 1994 NRECA G&T Rates Conference; San Antonio, Texas; June 5-8, 1994.

"Implementation of Demand-Side Component of IRP," NRECA's Finance for Marketing Professionals Workshop; Lincoln, Nebr.; 1993-95.

"Competing for Retail Loads," NRECA's 1994 G&T Legal Seminar; New Orleans, La., November 10, 1994.

"Transmission Access Revolution," NRECA's 1993 G&T Director's Update Conference; Nashville, Tenn.; December 2, 1993.

"Coordination of IRP and Marketing Strategy with G&T Wholesale Rate Design," NRECA's G&T Rates & G&T Marketing Conference; Lexington, Ky.; June 8, 1993.

"Rates as a Marketing Tool," NRECA's G&T Marketing Seminar; Denver, Colo.; September 10, 1992.

"Development of a Rate Strategy for the Cooperative System," 1991 Rural Electric Expo for NRECA; New Orleans, La.; February 2-3, 1991.

"Innovative Rate Forms," 1991 NRECA Engineering and Operations Conference; New Orleans, La.; January 31, 1991.

"Making Sense of Your System's Rate Structure," NRECA 1990 Member Services Communication Conference; Charlotte, N.C.; July 31, 1990.

"Service to Large Industrial Customers," NRECA's Rural Electric Management Council; Fargo, N. Dak.; May 17, 1989.

"Rate Design for Attracting and Maintaining Loads," NRECA's Management Internship Program; Lincoln, Nebr.; October 1, 1986.

"Preconference Workshop: Basic Issues in Rate Design," NRECA's 1986 National Accounting and Finance Conference; Tampa, Fla.; September 9, 1986.

"Marketing: Distribution Benefits Through Sale of Surplus Power and Jointly Designed Marketing Rates," 1987 NRECA Engineering and Operations Conference; Denver, Colo.; November 20, 1987.

Training - International

Rate Training Course presented for electric utility executives of Russia, coordinated through Institute of International Education; Moscow, Russia; November 1994.

Rate Training Course presented for electric utility executives of India, coordinated through Institute of International Education; Hyderabad, India; November 1994.

Rate Training Course presented for members of Bangladesh REB coordinated through NRECA; Oklahoma City, Okla.; October 28-November 8, 1991.

"Development of Rate Schedules for an Electric Utility," CAST/CSEE/NRECA Workshop; Kunming, Republic of China; May 14-19, 1984.

"A Planning Model for the Analysis of Long Range Distribution System Design Alternatives," IEEE PES Summer Meeting and EHV/UHV Conference; Vancouver, Canada; July 1973.

Presentations and Papers

"Rate Analysis and Cost of Service Study," presented with Judy Lambert to Region VIII Electric Cooperative Accountants' Association, in Oklahoma City, Okla., April 12, 2002.

"How to Position Cooperatives to Compete in a Customer-Choice Environment," presented to the Texas Statewide group in Austin, Texas; April 11, 2002.

"Positioning The Member Distribution Cooperative to Deal with a Customer Choice Environment," Panel discussion at Brazos Electric Cooperative's Strategic Planning Workshop; Waco, Texas; October 5, 2001.

"Restructuring Issues for the G&T," presented for G&T Accounting and Finance Association's 2000 Conference; Breckenridge, Colorado; June 19, 2000.

"The Restructuring of the Electric Power Industry in Oklahoma and in the Southwest," Panel Discussion Participant; Institute for Energy Economics and Policy, et al; Sarkeys Energy Center, The University of Oklahoma, Norman; December 10, 1999.

"Application of Leadership Skills," presentation for Dr. Jerry Holmes' engineering students at The University of Oklahoma, Norman; April 22 and December 2, 1999.

"Rate Design and the Changing Electric Industry," WREA Annual Meeting; Cheyenne, Wyoming; September 24, 1998.

"Rate Design and the Changing Electric Industry," CFC's Annual Meeting; Colorado Springs, Colorado; July 3, 1998.

"Preparing for the Future Cooperative Electric Service in Texas," presented to Texas Electric Cooperatives' Managers' Conference; Austin, Texas; December 5, 1996.

"Industry Restructuring Implications for Cooperatives," presented to Texas Electric Cooperatives' Government Relations Committee; Austin, Texas; July 1, 1996.

"The Economics of Serving Large Loads," Electric Cooperatives of South Carolina's Competitive Strategies Workshop, Columbia, S.C., August 15-16, 1995.

"Evolving Cooperative Structures," CFC's Cooperative Financing Forum; Chicago, Ill.; July 11, 1995.

"Takeover Workshop," Texas Electric Cooperatives, Inc.; Lubbock and Cleburne, Texas; April 6-7, 1995.

"The Power in the Partnership: Changing the Co-Op Power Supply," TEC 54th Annual Meeting; Fort Worth, Texas, August 2, 1994.

"Implementation of Demand-Side Component of IRP," Georgia EMC in coordination with NRECA; Ga., April 27, 1994.

"The Transmission Access Revolution," Special G&T Director's Update Program for Brazos Electric Power Cooperative, DFW Airport Marriott Hotel, Texas; March 21-22, 1994.

"Buy-Out and Refinancing of REA Loans: Factors to Consider in Evaluation Analysis," Texas Electric Cooperatives, Inc.; Austin, Texas; December 3, 1993.

"Update on Current Issues – Texas RECs and PUCT," Texas Electric Cooperatives, Inc.; Austin, Texas; November 15, 1993.

"The Co-Op Power Picture in Texas," TEC's 52nd Annual Meeting; Houston, Texas; July 28, 1992.

"Ratemaking Activities for Rural Electric Cooperatives," TEC's Seminar on Electric Cooperatives; Austin, Texas; October 18, 1991.

"Cost of Service Major Points," TEC Accounting Association Annual Meeting; San Antonio, Texas; April 20, 1990.

"Rate Design for Large Power Service and Options for Marketing and Incentive Rates," TEC Engineering Association; Austin, Texas; September 27, 1989.

"Revenue Requirements and Cost of Service Considerations at the PUC," TEC Engineering Association; Austin, Texas; April 28, 1988.

"Course 495.3 - Rate Issues and Philosophies," 1987 Wisconsin Electric Cooperative Association; Wisconsin Rapids, Wis.; December 1-3, 1987.

"Cost Bases for Incentive Rates Applicable to Industrial Loads," 1987 Conference on Industrial Energy Technology; Houston, Texas; September 16-17, 1987.

"Considerations in Cooperative Consolidations," with Martin Lowery at NRECA's 1987 Accounting and Finance Conference; Lexington, Ky.; September 9, 1987.

"Rates to Attract Attractive Loads," Association of Louisiana Electric Cooperatives, in coordination with AHP Systems, Inc.; Baton Rouge, La.; July 1-2, 1987.

"Rates to Attract Attractive Loads," Wisconsin Electric Cooperative Association in Coordination with AHP Systems, Inc.; Stephens Point, Wis.; February 12, 1987.

"Rate Seminar," Indiana Statewide Association of REC, Inc., (Co-Presenter: David Hedberg); Indianapolis, Ind.; September 25, 1986.

"Cost of Service and Rate Design Issues Affecting Industrial Customers in Retail Rate Proceedings," Public Utility Commission of Texas 1986 Industrial Energy Technology Conference; Houston, Texas; June 1986.

"The Importance of the Impact of Rates," NRECA's Management Services Conference -- Preparing Now to Prevent a Takeover or Sellout; Denver, Colo.; April 17-18, 1986; and New Orleans, La.; May 14-15, 1986.

"Energy Cost for Industrial Customers," (Co-Author: M.K. Moore) ACEC Research & Management Foundation's Industrial Energy Management Forum; Tempe, Ariz., March 26, 1986.

"Analysis of Financial and Operating Ratios," REA National Conference; San Antonio, Texas; July 10, 1985.

"Coordination of Wholesale/Retail Rate Design for Effective Marketing Strategy," NRECA's National Marketing Conference; Kansas City, Mo., June 5, 1985.

"Development of a Rate Analysis," NRECA Management Quarterly; Washington, D.C.; Volume 24, No. 3; Summer 1983.

"Cost Allocation Considerations for Rural Distribution Systems," NARUC Biennial Regulatory Information Conference; Columbus, Ohio; October 19, 1978.

"Cost Allocation Considerations and Methods for Electric Rate Analysis and Design for Rural Distribution Systems," IEEE Transactions on Industry Application; Volume 1A-13, No. 2; 1977.

"Design of Irrigation Rates Under Load Management Program," (Co-Authors: S.P. Patwardhan and B.E. Smith), presented at IEEE Rural Power Conference; Kansas City, Mo.; May 16, 1977.

"Cost Allocation Considerations and Methods for Electric Rate Analysis and Design for Rural Distribution Systems," IEEE Rural Electric Power Conference; Omaha, Nebr.; April 1975.

"A Financial Forecasting Model for Rural Electric Distribution Systems," IEEE PES Summer Power Meeting and Energy Resources Conference; Anaheim, Calif.; July 1974.

"Transmission Substation Control Using On-Site Computer Directed Simulation and Closed Loop Control," (Co-Author: H.E. Michel).

"The Development of Design Objectives for Electric Utility Rate Schedules," Master's Thesis; University of Oklahoma, Norman; 1969.

EXHIBIT CNS-2

Rating Methodology

Moody's Global
Corporate Finance

December 2009

U.S. Electric Generation & Transmission Cooperatives

Table of Contents:

Analyst Contacts:

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Summary

This rating methodology explains Moody's approach to assessing credit risk in the U.S. electric generation & transmission cooperative sector (G&T co-ops). It replaces the U.S. Electric Generation & Transmission Cooperatives rating methodology that was published in May 2006. While based on the same core principles as the May 2006 methodology, this updated framework incorporates refinements that better reflect the more recent challenges facing G&T co-ops and the way Moody's applies its industry methodologies.

The goal of this report is to help issuers, investors and other interested market participants understand how Moody's assesses credit risk for companies in the U.S. G&T cooperative industry, and to explain how key quantitative and qualitative risk factors map to specific rating outcomes. Cooperative structures in other global industrial sectors may be subject to a number of other considerations and are not intended to be covered by this rating methodology. Our objective is for users to be able to estimate in most cases, within two alpha-numeric rating notches, the likely senior most credit rating for a U.S. electric generation & transmission cooperative.

Moody's analysis of U.S. Electric G&T co-ops focuses on five key rating factors that are considered central to assigning ratings in this sector. The five rating factors encompass 14 elements (or sub-factors), each of which maps to specific letter ratings (see Appendix A). The number of sub-factors is reduced from 22 previously, largely reflecting a combination of several factors that were determined to be somewhat duplicative and to further simplify the rating methodology. The five key factors, which will be detailed in this report, are as follows:

1) Long-Term Wholesale Power Supply Contracts/Regulatory Status

2) Rate Flexibility

3) Member Profile

4) Financial Metrics

5) Size

Moody's Investors Service

In appendix B we have included a detailed rating grid for the 17 G&T co-ops included in this methodology. For each G&T co-op, the grid maps the key rating factors and sub-factors and shows the indicated alpha-numeric rating that is calculated from the overall combination of factors. We also include in appendix C discussions of "outliers" – G&T co-ops whose rating for a specific sub-factor differs by two or more broad rating categories from the actual rating, as G&T co-ops will not always map consistently to their overall rating on every sub-factor.

The purpose of the rating grid is to provide a reference tool that can be used to approximate credit profiles within the U.S. G&T co-op sector. The grid provides summarized guidance on the factors that Moody's believes are most important in assigning ratings to G&T co-ops. The grid is a summary rather than an exhaustive representation of every rating consideration and does not fit every business model equally well. In addition, many of our sub-factor mappings utilize historical financial or statistical data to illustrate the grid; however, our ratings also consider future expectations. Accordingly, the grid indicated rating is not expected to always match the actual rating of each G&T co-op. The text of the rating methodology provides insights on the key rating considerations that are not represented in the grid, as well as the circumstances in which the rating effect for a factor might be significantly different from the weight indicated in the grid.

Readers should also note that this rating methodology does not attempt to provide an exhaustive list of every factor that can be relevant to G&T co-op ratings. For example, our analysis covers factors that are common across all industries (such as debt leverage, liquidity, ownership, and legal structure) as well as factors that can be meaningful on a company specific basis (such as litigation, environmental or carbon exposure, capital expenditure needs, and customer and generation supply diversity).

This publication includes the following sections:

- **About the Rated Universe**: overview of the rated G&T co-op universe
- **About this Rating Methodology**: description of our rating methodology, including a detailed explanation of each of the key factors that drive ratings
- **Assumptions and Limitations**: Comments on the rating methodology's assumptions and limitations, including a discussion of other rating considerations that are not included in the grid

In addition to appendices A, B, and C, we also provide a brief industry overview (Appendix D) and a discussion of key rating issues for the G&T co-op sector over the intermediate term (Appendix E).

About The Rated Universe

An electric generation & transmission cooperative is a not-for-profit rural electric system whose primary function is to provide electric power on a wholesale basis to its owners. These owners are comprised of a group of distribution co-ops and in some instances may also include small G&T co-ops. Each distribution cooperative sells power on a retail basis to its customers, who are the members that own the distribution co-op.

Moody's currently rates 17 U.S. electric G&T cooperatives, included among which are many of the larger G&T co-ops and a growing number of the medium to smaller-sized ones. The group of 17 has approximately $22.1 billion of debt outstanding and collectively owns/controls or purchases approximately 41,000 megawatts of electric generation capacity. All of these issuers are currently rated investment grade and all except one pending review for possible downgrade and three negative rating outlooks currently carry a stable rating outlook. The G&T cooperatives currently occupy the investment-grade, single-A to high-Baa range.

The credit profile of G&T co-ops on the whole has been stable. Over the past three years, we have added six G&T cooperatives to our rated universe, including Great River Energy, Golden Spread Electric Cooperative, Minnkota Power Cooperative, South Mississippi Power, Big Rivers Electric Corp., and PowerSouth Energy Cooperative, bringing the total to 17 in all. In addition to the six new ratings assigned, three issuers were downgraded, none were upgraded, and three rating outlooks were changed to negative from stable. We also assigned three new commercial paper program ratings for Basin Electric Power Cooperative (Prime-1), Arkansas Electric Cooperative (Prime-1) and Chugach Electric Association (Prime-2). Chugach Electric Association's senior unsecured long-term rating was downgraded in December 2008 to A3 from A2 in conjunction with assigning a Prime-2 short-term rating to its commercial paper program. The downgrade reflected concerns about potential loss of wholesale revenue, re-financing risk, external financing of higher capital expenditures, and the potential need for higher rates, which are subject to Alaska regulatory jurisdiction. In April 2009, Hoosier Energy's senior secured rating was downgraded to Baa1 from A3 and kept on review for possible further downgrade, primarily due to concerns about ongoing litigation with John Hancock Life Insurance Company related to an existing leveraged lease transaction and the potential effects on its liquidity. In September 2009, Oglethorpe Power's rating outlook was changed to negative from stable, primarily reflecting concerns about the costs associated with its plans to partner with others in constructing a new nuclear plant, among other factors. In October 2009, Dairyland Power's A2 Issuer Rating was downgraded to A3 and its rating outlook is negative. The downgrade primarily reflected concerns about weak metrics compared to its prior rating level and the negative outlook captures ongoing concerns that soft market power rates in the Midwest may delay potential opportunities for Dairyland to take advantage of its strong baseload capacity profile by engaging in third party sales. On November 11, 2009, Buckeye Power's rating outlook was changed to negative from stable primarily reflecting the recent weakening of its credit metrics but also our concern as to how long it may take for improvement in the metrics to materialize given the softness in the economy of the region and lower than expected power prices for excess energy sales.

Meanwhile, we note that G&T co-ops have conservatively managed their businesses during the past three years by:

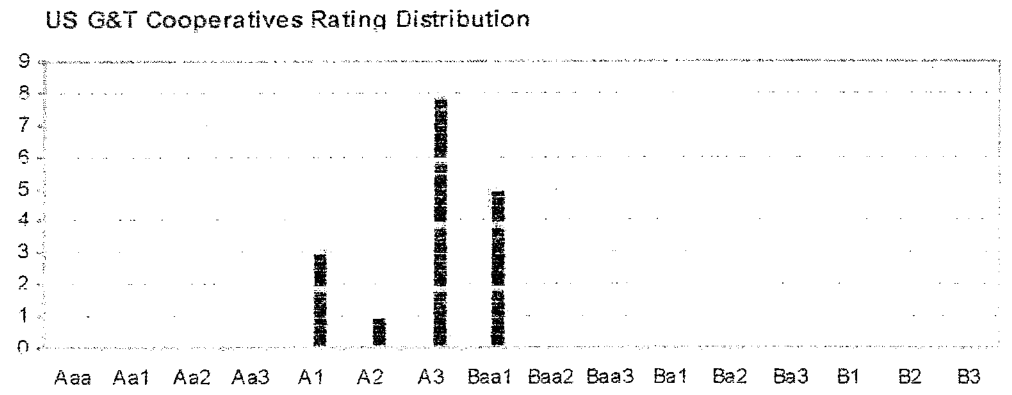
- using long term supply planning to meet increasing demands for power from their member co-ops,
- tightly controlling operating costs,
- increasing rates when necessary, and
- carefully attending to liquidity.

The following table illustrates the distribution of ratings in the U.S. G&T cooperative sector.

Rated Issuers

Company	Current Rating [1]	Commercial Paper/ Short-term Rating	Outlook	Total Debt ($ Millions) (d)
Arkansas Electric Cooperative	A2 (a)	P-1	Stable	644 (e)
Associated Electric Cooperative	A1		Stable	1,478
Basin Electric Power Cooperative	A1	P-1	Stable	2,287
Big Rivers Electric Corp.	(P) Baa1		Stable	1,039 (f)
Buckeye Power Inc.	A1		Negative	1,318
Chugach Electric Association	A3 (b)	P-2	Stable	346
Dairyland Power Cooperative	A3 (c)		Negative	973
Georgia Transmission	A3	P-2	Stable	1,560
Golden Spread Electric Cooperative	A3 (c)		Stable	161
Great River Energy	A3		Stable	2,362
Hoosier Electric Power	Baa1		RUR ↓	1,138
Minnkota Power Cooperative	Baa1 (c)		Stable	258
Oglethorpe Power Corp.	A3	P-2	Negative	4,127
Old Dominion Electric Cooperative	A3		Stable	783
PowerSouth	Baa1 (c)		Stable	1,411
South Mississippi Electric Power Association	A3		Stable	758
Tri-State G&T Association	Baa1		Stable	1,880
Total Unadjusted Debt of Rated G&T Co-ops				**22,524**

Notes:
[1] Ratings are senior secured unless otherwise noted
(a) Secured Facility Bonds ranking junior to RUS security
(b) Senior Unsecured Rating; No secured debt in capital structure
(c) Issuer Rating
(d) As of June 30, 2009, unless otherwise indicated
(e) As of July 31, 2009
(f) As of December 31, 2008



About This Rating Methodology

Moody's U.S. electric G&T cooperative rating methodology consists of the six sections listed below.

1) Identification of the Key Rating Factors

The grid in this methodology focuses on five broad rating factors, further broken down into 14 rating sub-factors and their weightings.

Rating Factor/Sub-Factor Weighting - U.S. Electric G&T Cooperatives

Broad Rating Factors	Broad Rating Factor Weighting	Rating Sub-Factor	Sub-Factor Weighting
Wholesale Power Contracts and Regulatory Status	20%	% Member Load Served and Regulatory Status	20%
Rate Flexibility	20%	Board Involvement / Rate Adjustment Mechanism	5%
		Purchased Power / Sales (%)	5%
		New Build Capex (% of Net PP&E)	5%
		Rate Shock Exposure	5%
Member / Owner Profile	10%	Residential Sales / Total Sales	5%
		Members' Consolidated Equity / Capitalization	5%
3-Year Average	40%	TIER	5%
G&T Financial Metrics		DSC	5%
		FFO / Debt	10%
		FFO / Interest	10%
		Equity / Capitalization	10%
G&T Size	*10%*	*MWh Sales*	5%
		Net PP&E	5%
Total	**100%**		**100%**

These factors are critical to the analysis of U.S. Electric G&T cooperatives and, in most instances, can be benchmarked across the sector. The discussion begins with a review of each factor and an explanation of its importance to the rating.

2) Measurement of Key Rating Factors

We explain the measurements we use to assess performance on each of the rating factors and sub-factors. We explain the rationale for using specific rating factors and provide insights on the way these are applied in the rating decision process. Many of the sub-factors are found in or derived from the financial statements of the G&T co-ops and those of their members, while others are calculated or derived using data gathered from various sources, and observations and estimates by Moody's analysts.

Moody's ratings are forward looking and incorporate our expectations of future financial and operating performance. We use both historical and projected financial results in the rating process; however, this document makes use only of historic data, and does so solely for illustrative purposes. Historical operating results help us understand the pattern of a company's performance and how it compares to its peers. Historical data also assists us in, among other things, looking through the earnings volatility that can sometimes occur during a given year and evaluating whether projected future results are realistic.

This rating methodology uses historical data in most instances based on information as of the latest fiscal year end; however, the sub-factors for financial metrics use three-year averages for the last three fiscal years.

All of the quantitative credit metric measures comprising the sub-factors in Factor 4 incorporate Moody's standard adjustments to the income statement, statement of cash flows, and balance sheet and include adjustments for certain off-balance sheet financings and certain other reclassifications in the income statement and statement of cash flows.

3) Mapping Factors to Rating Categories

After identifying the measurement criteria for each rating sub-factor, we provide a chart that maps the rating sub-factors to specific alpha rating categories (Aaa, Aa, A, Baa, Ba, or B). In this report, we provide a range or description for each of the measurement criteria. For example, we specify what level of FFO/Interest is generally acceptable for an A credit versus a Baa credit, etc.

4. Mapping Issuers to the Grid and Discussion of Grid Outliers

In this section (Appendix B), we provide a table showing how each company maps within the specific rating sub-factors. The weighted average of the sub-factor ratings produces a grid indicated rating for each broad factor. We also highlight companies (Appendix C) whose grid indicated performance on a specific factor or sub-factor is higher or lower by two or more broad rating categories from the actual rating. A company whose performance is two or more broad rating categories higher than its actual rating is deemed a positive outlier for that factor. A company whose performance is two or more broad rating categories below is deemed a negative outlier. We also discuss the general reasons for such outliers within a given factor or sub-factor.

5) Discussion of Assumptions, Limitations and Other Rating Considerations

This section discusses limitations in the use of the grid to map against actual ratings as well as limitations and key assumptions that pertain to the overall rating methodology.

6) Determining the Overall Grid-Indicated Rating

To determine the overall grid-indicated rating, the indicated rating category for each sub-factor is converted into a numeric value based upon the scale below.

Aaa	Aa	A	Baa	Ba	B
1	3	6	9	12	15

The numerical score for each sub-factor is multiplied by the weight for that sub-factor with the results then summed to produce a composite weighted-average factor score. The composite weighted-average factor score is then mapped back to an alpha-numeric rating based on the ranges in the grid below.

Composite Rating

Indicated Rating	Aggregate Weighted Factor Score
Aaa	$0.0 \leq x < 1.5$
Aa1	$1.5 \leq x < 2.5$
Aa2	$2.5 \leq x < 3.5$
Aa3	$3.5 \leq x < 4.5$
A1	$4.5 \leq x < 5.5$
A2	$5.5 \leq x < 6.5$
A3	$6.5 \leq x < 7.5$
Baa1	$7.5 \leq x < 8.5$
Baa2	$8.5 \leq x < 9.5$
Baa3	$9.5 \leq x < 10.5$
Ba1	$10.5 \leq x < 11.5$
Ba2	$11.5 \leq x < 12.5$
Ba3	$12.5 \leq x < 13.5$
B1	$13.5 \leq x < 14.5$
B2	$14.5 \leq x \leq 15.0$

For example, an issuer with a composite weighted factor score of 8.2 would have a Baa1 grid-indicated rating. We use a similar procedure to derive the grid-indicated ratings in the tables embedded in the discussion of each of the five broad rating factors.

The Key Rating Factors

Moody's analysis of U.S. G&T co-ops focuses on five broad rating factors:

- Long-Term Wholesale Power Supply Contracts/Regulatory Status
- Rate Flexibility
- Member Profile
- Financial Metrics
- Size

Factor 1: Long-Term Wholesale Power Supply Contracts/Regulatory Status

Why it Matters

Against a backdrop of significant spending for capital projects, volatile fuel costs and looming carbon legislation and related costs, the strength of the wholesale power contracts and the predictable revenue stream they provide for G&T co-ops remains a primary source of credit support. Because the prevalence of rate autonomy is similarly an integral credit factor linked to costs tied to the wholesale power contract, we have combined regulatory status of the G&T and its distribution member/owners, previously considered in Factors 2 and 3, respectively, into Factor 1. In doing so, we also increased the weighting for Factor 1 to 20% from 15% previously.

Long term wholesale power supply contracts between G&T co-ops and their members provide G&T co-ops with a high degree of assurance that costs and capital investment can be recovered from rates charged to customers. These contracts typically require the member co-ops to purchase all or virtually all of their supply requirements from the G&T co-op and generally stipulate that co-op members must pay their pro-rata portion of all of the G&T co-op's fixed and variable costs related to the generation, procurement and transmission of their respective energy needs.

G&T co-ops have more flexibility to increase rates in response to rising costs as regulatory approval is typically not required. The regulatory status/relationship with regulators is important because G&T co-ops that operate in states that have some form of regulatory authority over their rate setting activities may have more difficulty raising rates compared to peers who are not directly subject to regulatory control. Assessing a member/owner's regulatory status is also important because some are subject to rate regulation, in which case the member may be denied approval for a large rate increase, making it difficult to comply with its contractual obligations to the G&T co-op.

An unsupportive regulatory jurisdiction is a credit negative and leaves co-ops with less flexibility to raise rates if needed. In contrast, absence of regulatory control over the rate setting process is a credit positive. Most co-ops are not subject to rate regulation, and set the rates they charge their members after careful consideration of their underlying cost structure and expected demand for power. They calculate what level of revenues would be required in order to meet operating costs, minimum required interest, and debt service coverage covenants in the RUS mortgage and/or other debt indentures, while also providing some cushion of revenue and equity to protect against adverse events such as sudden increases in costs or operating difficulties with key generating plants.

How We Measure It for the Grid

Based on data that can be derived from various sources, we calculate the percentage of member power supply needs served under the long-term wholesale power contract(s), with consideration as to whether the contracts are all requirements or substantially all requirements in nature. An assessment of the wholesale power contract allows us to identify whether the member co-ops are required to purchase all or virtually all of their supply requirements from the G&T co-op. For G&T co-ops who are not subject to rate regulation, the indicated rating for Factor 1 can range from Aaa to B and is largely determined by the overall percentage of member sales made under the wholesale power contracts. To receive the highest score of Aaa requires a legislative statute that precludes regulatory intervention in any future rate setting process. There are no such instances that currently apply within the rated universe.

We understand that there are currently 10 states that have full regulatory jurisdiction over the level of rates that co-ops can charge their members. These states are: Arizona, Arkansas, Alaska, Kansas, Kentucky, Louisiana, Maine, Maryland, Vermont, and Wyoming. There are a few other states including Indiana, New Mexico, and Michigan where state commissions have partial jurisdiction over G&T co-ops. Even if 100% of members' needs are met through sales under the wholesale power contracts, G&T co-ops conducting business in any of the aforementioned states would receive an indicated rating for Factor 1 of A at best. Where precisely the few rate-regulated G&Ts score within the range of A to B depends not only on the percentage of members' needs met through sales under the wholesale power contract, but also on our consideration of how supportive of credit quality the regulatory practices are and our understanding of the type of working relationships that prevail between the co-ops and the regulators.

Factor 1: Long-Term Wholesale Power Supply Contracts and Regulatory Status (20%)

Percentage of Member Load Served under Wholesale Power Contracts and Regulatory Status	100% and G&T and its Distribution Member/Owner Cooperatives are Not Rate Regulated by State Commission; Legislative statute to preclude regulatory intervention in the future rate setting process	100% and G&T is Not Rate Regulated by State Commission; No legislative statute to preclude regulatory intervention in the future G&T rate setting process; Some Distribution Member/Owner Cooperatives May Be Subject to Rate Regulation by State Commission; Very Supportive Commission Practices; Very Good Regulatory Relationships	> 80% and/or G&T is Rate Regulated by State Commission; Some Distribution Member/Owner Cooperatives May Be Rate Regulated by State Commission; Very Supportive Commission Practices; Very Good Regulatory Relationships	> 70% and/or G&T is Rate Regulated by State Commission; Some Distribution Member/Owner Cooperatives May Be Rate Regulated By State Commission; Moderately Supportive Commission Practices; Reasonably Good Regulatory Relationships	< 70% and/or G&T is Rate Regulated by State Commission; Some Distribution Member/Owner Cooperatives May Be Rate Regulated By State Commission; Unsupportive Commission Practices; Generally Difficult Regulatory Relationships	< 60% and/or G&T is Rate Regulated by State Commission; Most Distribution Member/Owner Cooperatives are Rate Regulated By State Commission; Very Unsupportive Commission Practices; Often Contentious Regulatory Relationships

Factor 2: Rate Flexibility

Why it Matters

Prices for fuels used to generate electricity are unregulated in the U.S. and have been subject to dramatic fluctuation over the last couple of years. G&T co-ops need the flexibility to raise rates in order to cover sharply higher prices for fuels, in addition to rising operating costs, and costs associated with existing mandated environmental requirements and those inevitably forthcoming related to carbon emissions along with any capital investment associated with construction of new plants (especially nuclear powered), among other factors.

We note that the number of sub-factors in Factor 2 have been reduced to four from six previously, as regulatory status was combined into Factor 1 and rate competitiveness was combined into Rate Shock Exposure. In doing so, each of the remaining four sub-factors in Factor 2 have been assigned a 5% weighting.

Board Involvement/Rate Adjustment Mechanisms: The extent to which a G&T co-op can ensure timely and full recovery of its costs and investments will have an integral effect on its overall financial performance and thus its creditworthiness. Each G&T coop's board of directors has a fiduciary responsibility to approve, or, where rate regulation applies, to seek regulatory approval of rates that ensure compliance with the financial covenants associated with debt indentures. To the extent that unexpected events arise, causing concerns about ability to comply with covenants, the board should be expected to move quickly to adjust rates upward when needed. Also, variable cost adjustment mechanisms provide for more automatic changes in rates when costs change and increase the speed with which rates can be increased when costs increase. The extent to which variable cost adjustment mechanisms are available is especially important where regulatory jurisdiction applies to a G&T co-op. The existence of variable cost adjustment mechanisms is a credit strength, especially when rate adjustments can be implemented at frequent intervals. Such mechanisms mitigate liquidity pressures that might otherwise arise when the cost of fuels exceeds rates in effect at that time.

Degree of Reliance on Purchased Power: Most of the power supply needs of G&T co-op members are met from generating plants owned by the G&T coops. Some G&Ts rely on market purchases of power to meet a portion of the member needs because their owned resources are insufficient, uneconomic, or periodically unavailable.

Assessing the degree of reliance on purchased power to meet members' demand and the rationale behind that strategy is important because G&Ts who purchase large amounts of power from the market to meet member demands may face increased price volatility for one of their largest costs. Relying on such a strategy also heightens the importance of liquidity, risk management policies and procedures, and counterparty credit assessment.

New Build Exposure Relative to Existing Asset Base: This factor is important because G&T co-ops largely finance capital investment with debt and rely upon rate increases to service the debt. When construction is delayed or runs above budget, the rate increases needed to cover the increased costs could lead to member resistance.

Potential for Rate Shock Exposure: In many respects, the potential for rate shock exposure is linked to rate competitiveness, so we have combined our consideration of rate competitiveness into this sub-factor as part of this updated methodology. Assessing the potential for rate shock exposure is important because a large rate increase can lead to member resistance even when the new higher level of rates is still competitive with other providers of power in the region. If the G&T co-op's rates are noticeably higher than other providers in its geographic area, member unrest could lead to contract challenges or possible withdrawal from the co-op.

How We Measure It for the Grid

Board Involvement/Rate Adjustment Mechanisms: The timing and extent to which a G&T co-op can increase rates is impacted by the activity of its board of directors and a number of rate adjustment mechanisms.

First we assess how active a board has been from a historical perspective with respect to approving or seeking regulatory approval of rate increases and consider the extent to which past behavior might change. To the extent that unexpected events arise, causing concerns about ability to comply with covenants, we believe the board should be expected to move quickly to adjust rates upward when needed. Those G&T co-ops whose boards of directors are exceptionally proactive in adjusting rates as necessary and who benefit from legislative statute that would preclude regulatory intervention in the future rate setting process would most likely receive the highest indicated ratings. In contrast, G&T co-ops with less active or even inactive boards of directors and who otherwise face uncertainty surrounding the extent and timing of cost recovery would receive much lower indicated ratings for this sub-factor.

With respect to situations where variable cost adjustment mechanisms apply, rates that can automatically adjust to fuel and/or purchased power cost increases without requiring action by the Board or regulators are viewed more favorably and generally result in a higher indicated rating for this sub-factor. In instances where recovery of variable cost increases is deferred, we consider the time period over which recovery occurs, with shorter periods obviously being better from a liquidity and credit quality standpoint.

Degree of Reliance on Purchased Power: To measure the degree to which a G&T relies on purchased power in conducting its business, we divide the amount of megawatt hours it purchases during the most recent fiscal year by the total megawatt hours of energy it sells. This data can usually be found in the G&T co-op's latest annual report and/or other published data sources. In those instances where a G&T co-op relies on purchased power to meet less than 40% of its energy requirements during a given fiscal year, the indicated rating for this sub-factor would be at least Baa and improve gradually as the percentage declines according to the Factor 2 table descriptions. Conversely, where the dependence on purchased power exceeds the 40% level, then the indicated rating would be Ba or lower according to the Factor 2 table descriptions.

New Build Exposure Relative to Existing Asset Base: To measure this sub-factor, Moody's divides the estimated future capital expenditures for a particular G&T co-op over the next five years by the net property, plant, and equipment report for the latest fiscal year end. The lower the resulting percentage from this calculation is, the better the indicated rating for the sub-factor will likely be, as the G&T will likely face less need to issue debt and increase rates to cover the higher financing costs.

Potential for Rate Shock Exposure: To measure the potential for rate shock exposure, Moody's continues to look at the extent to which a G&T relies on purchased power to meet its energy demand during the latest fiscal year and its new build exposure. A lower percentage in both instances is generally viewed more favorably under the methodology. In addition, we have expanded our measurement criteria for this sub-factor to also consider the G&T's reliance on coal and other carbon emitting generating resources. Those G&Ts with a high reliance on such resources will be scored lower on this sub-factor due to their vulnerability to potential carbon legislation and accompanying carbon costs.

Cost competitive G&T co-ops have greater flexibility to raise rates to offset cost increases or to build additional equity and would therefore be more likely to receive a higher indicated rating for this sub-factor than those G&Ts who are competitively challenged. Favorable characteristics include low or improving cost structure, lower wholesale prices versus peers, and low distribution member rates versus competitors in the region. Moody's also assesses a G&T co-op's prospects to *realize future rate increases in order to offset increasing* costs, as compared with others in the region although consistent rate data is often not publicly available. Nonetheless, Moody's seeks whatever public information is available, as well as confidential information on a company by company basis.

Factor 2 - Rate Flexibility (20%)

	Aaa	Aa	A	Baa	Ba	B	Sub-Factor Weighting
Assess Board Involvement in Setting Rates / Variable Cost Adjustment Mechanisms	Exceptionally proactive board that supports management recommendations for timely adjustment of rates to cover all costs of service; no regulatory intervention in the rate setting process; Legislative statute to preclude regulatory intervention in the future rate setting process	Proactive board that supports management recommendations for timely adjustment of rates to cover all costs of service; no regulatory intervention in the rate setting process; No legislative statute to preclude regulatory intervention in the future rate setting process	Active board in support of timely rate filings; possibility for regulatory intervention in the rate setting process in certain instances; frequent fuel cost adjustment capability in place under regulatory practice; timely recovery of any deferrals	Reasonably active board in support of timely rate filings; annual fuel cost adjustment capability in place under regulatory practice; reasonably timely recovery of any deferrals	Inactive board; limited, if any ability to adjust for fuel cost variability; uncertainty surrounding recovery of deferrals	Inactive board; no ability to adjust for fuel cost variability; uncertainty surrounding recovery of deferrals	5%
Purchased Power/Total MWh Sales (%)	x < 5%	5% ≤ x < 20%	20% ≤ x < 30%	30% ≤ x < 40%	40% ≤ x < 60%	x ≥ 60%	5%
New Build Exposure (Prospective 5-yr New Build Capex as % Net PP&E)	x < 5%	5% ≤ x < 25%	25% ≤ x < 50%	50% ≤ x < 75%	75% ≤ x ≤ 120%	x > 120%	5%
Potential for Rate Shock Exposure	Better rates than all others in the region on a consistent basis; Extremely low (e.g. Less than 10% reliance on purchased power and less than 10% 5-year-newbuild capex as percentage of latest year-end Net PP&E; and 0-20% of generation from carbon fuels	Much better rates than most in the region on a consistent basis; Very low (e.g. less than 20% reliance on purchased power and less than 25% 5-year-newbuild capex as percentage of latest year-end Net PP&E; and 20-40% of generation from carbon fuels	Better rates than most in the region on a consistent basis; Low (e.g. less than 30% reliance on purchased power and/or less than 50% 5-year-newbuild capex as percentage of latest year-end Net PP&E; and/or 40-55% of generation from carbon fuels	Better rates than some and worse rates than some in the region on a consistent basis; Moderate (e.g. less than 40% reliance on purchased power and/or less than 75% 5-year-newbuild capex as percentage of latest year-end Net PP&E; and/or 55-70% of generation from carbon fuels	Worse rates than most in the region on a consistent basis; High (e.g. greater than 40% reliance on purchased power or greater than 75% 5-year-newbuild capex as percentage of latest year-end Net PP&E; and/or 70-85% of generation from carbon fuels	Worse rates than all in the region on a consistent basis; Very high (e.g. greater than 40% reliance on purchased power and greater than 75% 5-year-newbuild capex as percentage of latest year-end Net PP&E; and/or 85-100% of generation from carbon fuels	5%

Factor 3: Member Profile

Why it Matters

Assessing the member profile of a G&T co-op is important because the members who own the G&T co-op are also its primary source of cash flow. Similar to the way we would assess the counterparty credit risk for an IOU that sells sizable amounts of power to another entity, or buys significant amounts of power from a wholesale power producer, we are concerned about the overall creditworthiness of the members. Although we still seek information about the members' expected consolidated demand growth and their consolidated assets, to further simplify this methodology, these two sub-factors previously included in the May 2006 methodology are not specifically incorporated into this update. The following two sub-factors, which are weighted at 5% each, continue to provide good insight into the members' creditworthiness and ability to meet obligations to the G&T co-op under the long-term wholesale power contract.

Residential Sales as a Percentage of Total Sales: The diversity of the members' retail customer mix is important in our analysis of G&T co-ops because substantial reliance upon any single customer or a small number of customers (such as large industrial customers) tends to be associated with greater variability of revenue. Members who own the G&T co-ops tend to serve large residential customer bases, with a majority of energy being sold to such customers, although some sales may be to more volatile industrial and commercial customers. A higher percentage of sales to residential customers is favorable because such sales are generally more stable and predictable.

Members Consolidated Equity to Capitalization: The financial condition of the member/owners, as measured in part by the members' consolidated equity to capitalization, is important because it affects their ability to perform under the wholesale power contracts that members have with their G&T co-op. For the most part, distribution co-ops carry less business and financial risk than G&T co-ops. The difference in the financial strength is largely attributable to the fact that the RUS has historically set tighter financial covenants for the distribution co-ops than for the G&T co-ops. In addition, the distribution co-ops are far less capital intensive than G&T co-ops who own generation assets. Distribution co-ops typically maintain higher levels of equity to total capitalization and stronger interest coverage ratios than G&T co-ops.

How We Measure It for the Grid

Residential Sales as a Percentage of Total Sales: To measure this sub-factor, we first generally aggregate the individual residential energy sales and total energy sales for each member/owner of a particular G&T co-op in the latest fiscal year. This information is generally available through requests made to the G&T because their members provide this data to them. The aggregate residential energy sales level is then divided by the aggregate total energy sales level to derive the aggregate percentage for the year. Under the Methodology, a higher percentage of more stable and predictable residential sales is viewed more favorably than a concentration of sales to large commercial and/or industrial customers.

Members Consolidated Equity to Capitalization: This sub-factor is measured by simply aggregating each member's total equity and debt as reported for the latest fiscal year end. The aggregate totals are then used to divide total members' debt by the sum of total members' debt plus equity. Members generally file financial statements with the RUS or otherwise make such statements available to the G&T that they have an ownership interest in. Most of the G&T co-ops that are covered by the methodology fall into the Baa or A category with consolidated member equity to capitalization in the range of 25% to 50%.

Factor 3 - Member/Owner Profile (10%)

	Aaa	Aa	A	Baa	Ba	B	Sub-Factor Weighting
Residential Sales/ Total Sales (%)	x ≥ 80%	75% ≤ x < 80%	50% ≤ x < 75%	40% ≤ x < 50%	20% ≤ x < 40%	x < 20%	5%
Members' Consolidated Equity/Capitalization (%)	x ≥ 65%	55% ≤ x < 65%	50% ≤ x < 55%	25% ≤ x < 50%	20% ≤ x < 25%	x < 20%	5%

Factor 4: G&T Financial Metrics

Why it Matters

Financial strength is an important indicator of a G&T co-op's ability to meet its obligations, including debt service. Moody's considers historical coverage ratios and also places a significant emphasis on the expected trend for coverage metrics when assessing the credit risk of G&T co-ops. In the interest of reducing the number of sub-factors and simplifying this methodology, we dropped the net operating margin metric from

Factor 4 as part of the update of this methodology since the net margin component of the coverage calculations already captures the operating profit. In doing so, we also adjusted the weighting of the remaining five sub-factors in Factor 4 to retain the overall 40% weighting for financial metrics. Nevertheless, we continue to highlight that while some G&T co-ops have large investment portfolios that considerably augment the bottom line, we consider it important that the G&T co-op be profitable on an operating basis. G&T co-ops that *rely extensively on profits from investment portfolios and diversified operations to compensate for negative* G&T operating margins are still viewed negatively.

Scores under Factor 4 may be higher or lower than what might be produced based on historical results, depending on our view of expected future financial performance.

Times Interest Earned Ratio (TIER) and Debt Service Coverage Ratio (DSC): These two ratios are important because they have governed RUS loan documentation for many years. In addition to TIER and DSC, Moody's also looks at margins for interest (MFI) as defined in certain indentures.

Funds from Operations Coverage of Interest (FFO/Interest) and FFO/Debt. The FFO/Interest and FFO/Debt metrics are important because they provide insight regarding the amount and quality of a G&T co-op's cash flow and its ability to service its debt.

Equity/Total Adjusted Capitalization: Moody's evaluates the G&T co-op's equity as a percentage of total adjusted capitalization to see how much flexibility there is in the balance sheet to absorb unexpected events. When measuring the level of equity cushion, G&T co-ops and the RUS have tended to rely on equity expressed as a percentage of total assets. However, Moody's and many investors prefer to measure equity as a percentage of total capitalization, because it facilitates comparison with IOU capital structures.

How We Measure It for the Grid

See Moody's Ratings Methodology: Moody's Approach to Global Standard Adjustments in the Analysis of Financial Statements for Non-Financial Corporations - Part 1, July 2005. The ratios used as a basis for this methodology are three year averages of calculations using the latest three fiscal year end statements, including standard adjustments. Three-year averages are used in part to smooth out some of the year to year volatility in financial performance and financial statement ratios. The ranges for each of the five metrics that would correspond to a particular indicated rating category appear in the table at the bottom of this section. The individual metric definitions are as follows:

TIER:

(Net margins, as represented by net profit after tax before unusual items + Interest + Income Tax) / Interest

DSCR:

(Net margins, as represented by net profit after tax before unusual items + Interest + Depreciation & Amortization) / (Interest + Principal Payment)

FFO / Interest:

(Funds from operations + Interest expense)/ Interest expense

FFO / Debt:

Funds from operations / (Short Term Debt + Long Term Debt, gross)

Equity / Total Capitalization:

(Deferred Taxes + Minority or Non-controlling Interest + Book Equity) / (Short Term Debt + Long Term Debt, gross + Deferred Taxes + Minority or Non-controlling Interest + Book Equity)

Factor 4 - 3-Year Average G&T Financial Metrics (40%)

	Aaa	Aa	A	Baa	Ba	B	Sub-Factor Weighting
TIER	x ≥ 1.6x	1.4x ≤ x < 1.6x	1.2x ≤ x < 1.4x	1.1x ≤ x < 1.2x	1.0x ≤ x < 1.1x	x < 1.0x	5%
DSC	x ≥ 1.9x	1.4x ≤ x < 1.9x	1.2x ≤ x < 1.4x	1.1x ≤ x < 1.2x	1.0x ≤ x < 1.1x	x < 1.0x	5%
FFO/Debt	x ≥ 15%	10% ≤ x < 15%	6% ≤ x < 10%	3% ≤ x < 6%	2% ≤ x < 3%	x < 2%	10%
FFO/Interest	x ≥ 3.25x	2.5x ≤ x < 3.25x	2.0x ≤ x < 2.5x	1.5x ≤ x < 2.0x	1.2x ≤ x < 1.5x	x < 1.2x	10%
Equity/Total Capitalization	x ≥ 50%	35% ≤ x < 50%	20% ≤ x < 35%	5% ≤ x < 20%	3% ≤ x < 5%	x < 3%	10%

Factor 5: G&T Size

Why it Matters

Size, together with Factor 3, Member Profile, has the lowest weighting of the five key factors because it tends to be less important for entities, such as G&T coops, that are subject to limited competition. As part of the update to this methodology, we have eliminated two sub-factors from Factor 5 (i.e. megawatts owned/purchased and revenues) because we found that they were somewhat duplicative and wanted to further simplify the methodology. Nevertheless, we still find that size, as measured by the following two sub-factors, which are weighted at 5% each, does matter.

Megawatt hour sales: This sub-factor is important because it is an indicator for economies of scale (i.e., a G&T co-op is better off if it can spread its fixed costs over a larger number of megawatt hours of electricity, thereby increasing its price competitiveness).

Net Property, Plant, and Equipment: This sub-factor is important because G&T co-ops can benefit from having a larger pool of assets and a more diverse source of fuels to run the generation assets it owns. A G&T co-op that has its assets concentrated in one generating plant could be subject to extreme cost pressures to the extent that it has to buy power on the open market due to an extended outage at its sole generating plant. Similarly, overdependence on one particular fuel source could materially raise costs during a period of prolonged price increases for that commodity.

How We Measure It for the Grid

We identify the amount of megawatt hour sales and net property, plant, and equipment data primarily from the G&T co-op's latest annual report. See the Factor 5 table below for the ranges that would apply for a particular indicated rating for the two sub-factors in Factor 5.

Factor 5 - G&T Size (10%)

	Aaa	Aa	A	Baa	Ba	B	Sub-Factor Weighting
Megawatt hour sales (Millions of MWhs)	*x ≥ 50*	*20 ≤ x < 50*	*11 ≤ x < 20*	*5 ≤ x < 11*	*3 ≤ x < 5*	*x < 3*	5%
Net PP&E ($ in Billions)	x ≥ 5	2 ≤ x < 5	1 ≤ x < 2	0.4 ≤ x < 1	0.3 ≤ x < 0.4	x < 0.3	5%

Rating Methodology Assumptions and Limitations, and Other Rating Considerations

The rating methodology grid incorporates a trade-off between simplicity that enhances transparency and greater complexity that would enable the grid to map more closely to actual ratings. The five rating factors in the grid do not constitute an exhaustive treatment of all the considerations that are important for ratings of

G&T co-ops. In addition, our ratings incorporate expectations for future performance, while the financial information that is used to illustrate the mapping in the grid is mainly historical. In some cases, our expectations for future performance may be informed by confidential information that we cannot publish. In other cases, we estimate future results based upon past performance, industry trends, demand and price outlook, peer actions and other factors. In either case, predicting the future is subject to the risk of substantial inaccuracy.

In choosing the metrics for this rating methodology grid, we did not include certain important factors that are common to all companies in any industry, such as the quality and experience of management, assessments of corporate governance and quality of financial reporting and information disclosure. The assessment of these factors can be highly subjective and ranking them by rating category in a grid would, in some cases, suggest too much precision in the relative ranking of particular issuers that are rated in various industry sectors.

Ratings may include additional factors that are difficult to quantify or that only have a meaningful effect in differentiating credit quality in some cases. Such factors include environmental obligations, nuclear decommissioning trust obligations, industrial customer concentrations, financial controls, and the political and economic environment, including possible government interference.

As an example, industrial exposure can vary considerably across the rated universe and this customer class can sometimes be subjected to more cyclicality in terms of energy consumption, which cannot be consistently represented in a simple grid format.

Actual ratings assigned may also reflect circumstances in which the weighting of a particular factor will be different from the weighting suggested by the grid. For example, Factors 1 and 2 address long term wholesale power contracts/regulatory status and rate flexibility, respectively; however, there may be instances where the effects of a G&T cooperative's financial metrics will be given greater consideration in an assigned rating than what is indicated by the weighting in the grid.

Conclusion: Summary of the Grid-Indicated Rating Outcomes

The objective of our methodology is for users to be able to estimate in most cases, within two alpha-numeric rating notches, the likely senior most credit rating for a U.S. electric generation & transmission cooperative. For consistency in drawing our conclusions, we rely upon an implied senior secured rating (i.e. the implied senior most rating) for the six G&T cooperatives who have senior secured debt in their respective capital structures but whose current ratings are either senior unsecured Issuer Ratings or whose current ratings apply to a class of debt junior to the senior secured debt. The methodology grid-indicated ratings map to Moody's current assigned or implied senior most ratings as follows (See Appendix B for the details):

Eight cooperatives or 47% have indicated ratings that match the Moody's actual (or implied) senior most rating,

six cooperatives or 35% have indicated ratings within one-notch of Moody's actual (or implied) senior most rating, and

three cooperatives or 18% have an indicated rating within two-notches of Moody's actual (or implied) senior most rating.

APPENDIX A: U. S. Electric G&T Cooperative Methodology Factor Grid

Factor 1: Long-Term Wholesale Power Supply Contracts and Regulatory Status

Weighting: 20%	[illegible]	[illegible]	A	[illegible]	[illegible]	[illegible]	Sub-factor Weighting
Percentage of Member Load Served under Wholesale Power Contracts and Regulatory Status	100% and G&T and its Distribution Member/Owner Cooperatives are Not Rate Regulated by State Commission; Legislative statute to preclude regulatory intervention in the future rate setting process	100% and G&T is Not Rate Regulated by State Commission; No legislative statute to preclude regulatory intervention in the future G&T rate setting process; Some Distribution Member/Owner Cooperatives May Be Subject to Rate Regulation by State Commission; Very Supportive Commission Practices; Very Good Regulatory Relationships	> 80% and/or G&T is Rate Regulated by State Commission; Some Distribution Member/Owner Cooperatives May Be Rate Regulated by State Commission; Very Supportive Commission Practices; Very Good Regulatory Relationships	> 70% and/or G&T is Rate Regulated by State Commission; Some Distribution Member/Owner Cooperatives May Be Rate Regulated By State Commission; Moderately Supportive Commission Practices; Reasonably Good Regulatory Relationships	< 70% and/or G&T is Rate Regulated by State Commission; Some Distribution Member/Owner Cooperatives May Be Rate Regulated By State Commission; Unsupportive Commission Practices; Generally Difficult Regulatory Relationships	< 60% and/or G&T is Rate Regulated by State Commission; Most Distribution Member/Owner Cooperatives are Rate Regulated By State Commission; Very Unsupportive Commission Practices; Often Contentious Regulatory Relationships	20%

Factor 2: Rate Flexibility

[illegible]	[illegible]	[illegible]	A	[illegible]	[illegible]	[illegible]	Sub-factor Weighting
Assess Board Involvement in Setting Rates / Variable Cost Adjustment Mechanisms	Exceptionally proactive board that supports management recommendations for timely adjustment of rates to cover all costs of service; no regulatory intervention in the rate setting process; Legislative statute to preclude regulatory intervention in the future rate setting process	Proactive board that supports management recommendations for timely adjustment of rates to cover all costs of service; no regulatory intervention in the rate setting process; No legislative statute to preclude regulatory intervention in the future rate setting process	Active board in support of timely rate filings; possibility for regulatory intervention in the rate setting process in certain instances; frequent fuel cost adjustment capability in place under regulatory practice; timely recovery of any deferrals	Reasonably active board in support of timely rate filings; annual fuel cost adjustment capability in place under regulatory practice; reasonably timely recovery of any deferrals	Inactive board; limited, if any ability to adjust for fuel cost variability; uncertainty surrounding recovery of deferrals	Inactive board; no ability to adjust for fuel cost variability; uncertainty surrounding recovery of deferrals	5%
Purchased Power/Total MWh Sales (%)	x < 5%	5% ≤ x < 20%	20% ≤ x < 30%	30% ≤ x < 40%	40% ≤ x < 60%	x ≥ 60%	5%
New Build Exposure (Prospective 5-yr New Build Capex as % Net PP&E)	x < 5%	5% ≤ x < 25%	25% ≤ x < 50%	50% ≤ x < 75%	75% ≤ x ≤ 120%	x > 120%	5%
Potential for Rate Shock Exposure	Better rates than all others in the region on a consistent basis; Extremely low (e.g. Less than 10% reliance on purchased power and less than 10% 5-year-newbuild capex as percentage of latest year-end Net PP&E; and 0-20% of generation from carbon fuels	Much better rates than most in the region on a consistent basis; Very low (e.g. less than 20% reliance on purchased power and less than 25% 5-year-newbuild capex as percentage of latest year-end Net PP&E; and 20-40% of generation from carbon fuels	Better rates than most in the region on a consistent basis; Low (e.g. less than 30% reliance on purchased power and/or less than 50% 5-year-newbuild capex as percentage of latest year-end Net PP&E; and/or 40-55% of generation from carbon fuels	Better rates than some and worse rates than some in the region on a consistent basis; Moderate (e.g. less than 40% reliance on purchased power and/or less than 75% 5-year-newbuild capex as percentage of latest year-end Net PP&E; and/or 55-70% of generation from carbon fuels	Worse rates than most in the region on a consistent basis; High (e.g. greater than 40% reliance on purchased power or greater than 75% 5-year-newbuild capex as percentage of latest year-end Net PP&E; and/or 70-85% of generation from carbon fuels	Worse rates than all in the region on a consistent basis; Very high (e.g. greater than 40% reliance on purchased power and greater than 75% 5-year-newbuild capex as percentage of latest year-end Net PP&E; and/or 85-100% of generation from carbon fuels	5%

Factor 3: Member / Owner Profile

Weighting - [illegible]	Aaa	Aa	A	Baa	Ba	B	Sub-Factor Weighting
Residential Sales/Total Sales (%)	x ≥ 80%	75% ≤ x < 80%	50% ≤ x < 75%	40% ≤ x < 50%	20% ≤ x < 40%	x < 20%	5%
Members' Consolidated Equity/Capitalization (%)	x ≥ 65%	55% ≤ x < 65%	50% ≤ x < 55%	25% ≤ x < 50%	20% ≤ x < 25%	x < 20%	5%

Factor 4: 3-Year Average G&T Financial Metrics

Weighting - [illegible]	Aaa	Aa	A	Baa	Ba	B	Sub-Factor Weighting
TIER	x ≥ 1.6x	1.4x ≤ x < 1.6x	1.2x ≤ x < 1.4x	1.1x ≤ x < 1.2x	1.0x ≤ x < 1.1x	x < 1.0x	5%
DSC	x ≥ 1.9x	1.4x ≤ x < 1.9x	1.2x ≤ x < 1.4x	1.1x ≤ x < 1.2x	1.0x ≤ x < 1.1x	x < 1.0x	5%
FFO/Debt	x ≥ 15%	10% ≤ x < 15%	6% ≤ x < 10%	3% ≤ x < 6%	2% ≤ x < 3%	x < 2%	10%
FFO/Interest	x ≥ 3.25x	2.5x ≤ x < 3.25x	2.0x ≤ x < 2.5x	1.5x ≤ x < 2.0x	1.2x ≤ x < 1.5x	x < 1.2x	10%
Equity/Total Capitalization	x ≥ 50%	35% ≤ x < 50%	20% ≤ x < 35%	5% ≤ x < 20%	3% ≤ x < 5%	x < 3%	10%

Factor 5: G&T Size

Weighting - 10%	Aaa	Aa	A	Baa	Ba	B	Sub-Factor Weighting
Megawatt hour sales (Millions of MWhs)	x ≥ 50	20 ≤ x < 50	11 ≤ x < 20	5 ≤ x < 11	3 ≤ x < 5	x < 3	5%
Net PP&E ($ in Billions)	x ≥ 5	2 ≤ x < 5	1 ≤ x < 2	0.4 ≤ x < 1	0.3 ≤ x < 0.4	x < 0.3	5%

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APPENDIX B: Methodology Grid-Indicated Ratings

Rating Factors				Factor 1: Wholesale Power Contracts / Reg Status	Factor 2: Rate Flexibility				Factor 3: Member/Owner Profile		Factor 4: 3-Year Average G&T Financial Metrics					Factor 5: G&T Size	
	Current Rating [1]	Outlook	Indicated Rating	% Memb. Load Served & Reg Stat	Board Involve/Rate Adj. Mech.	Purch. Pwr / Sales (%)	New Build Capex (% Net PP&E)	Rate Shock	Resid. Sales	Member Consol. Eq / Cap	TIER	DSC	FFO / Debt	FFO / Interest	Eq / Cap	MWh sales	Net PP&E
Factor Weighting				20%	5%	5%	5%	5%	5%	5%	5%	5%	10%	10%	10%	5%	5%
Arkansas Electric	A2 (a)	Stable	A3	Baa	A	Aa	Ba	Ba	A	Baa	A	Baa	A	Aa	Aa	A	Baa
Associated Electric	A1	Stable	A2	Aa	Aa	Aa	Baa	Ba	A	A	A	A	A	A	Baa	Aa	A
Basin Electric Power	A1	Stable	A1	Aa	Aa	Aa	B	Ba	Ba	Baa	Aaa	Aa	Aa	Aa	A	A	Aa
Big Rivers Electric Corp.	(P) Baa1	Stable	Baa2	Aa	Baa	B	A	B	B	Baa	Aa	Aa	Baa	Baa	B	Baa	Baa
Buckeye Power	A1	Negative	A1	Aa	Aa	Aa	A	B	A	A	A	A	A	Aa	A	Baa	A
Chugach Electric Assoc.	A3 (b)	Stable	A3	Baa	A	Aa	Ba	B	A	Baa	A	Aa	Aa	Aa	A	B	Baa
Dairyland Power	A3 (c)	Negative	Baa1	Aa	Aa	Aa	A	B	A	Baa	Ba	Ba	Baa	Baa	Baa	Baa	Baa
Georgia Transmission	A3	Stable	A2	Aa	Aa	Aa	Baa	Aa	A	Baa	Baa	Ba	Baa	Baa	Baa	Aa	A
Golden Spread Electric	A3 (c)	Stable	A2	A	Aa	B	Ba	B	A	Baa	Aaa	Aaa	Aaa	Aaa	Aaa	Baa	B
Great River Energy	A3	Stable	A3	A	Aa	Baa	Ba	B	A	Baa	A	Baa	A	A	Baa	A	Aa
Hoosier Electric Power	Baa1	RUR ↓	A2	Aa	Baa	A	Baa	B	A	Aa	A	A	A	Aa	Baa	Baa	Baa
Minnkota Power	Baa1 (c)	Stable	A3	Aa	Aa	A	Ba	B	A	Baa	Baa	Baa	Baa	A	Aa	Ba	B
Oglethorpe Power Corp.	A3	Negative	Baa1	A	A	Aa	Ba	Baa	A	Baa	Ba	Ba	Baa	Baa	Baa	Aa	Aa
Old Dominion Electric	A3	Stable	A2	Aa	A	Ba	A	Baa	A	Baa	A	Aa	A	A	A	Baa	A
PowerSouth	Baa1 (c)	Stable	A3	Aa	Aa	Baa	A	B	A	Baa	A	A	Baa	A	Baa	Baa	A
South Mississippi	A3	Stable	A3	Aa	Aa	B	Ba	Ba	A	A	A	Baa	A	A	Baa	Baa	Baa
Tri-State G&T Assoc.	Baa1	Stable	A3	Aa	A	Baa	Ba	B	Ba	Baa	Aaa	Baa	A	Aa	Baa	A	Aa

APPENDIX C: Observations and Outliers for Grid Mapping

Factor 1: Ratings Mapping

The following table details the mapping for the Nature of Long-Term Wholesale Power Supply Contracts/Regulatory Status factor:

FACTOR 1 (20%) Nature of Long-Term Wholesale Power Supply Contracts and Regulatory Status				Negative Outlier / Positive Outlier
G&T Co-op	Current Rating [1]	Outlook	% of Member Load Served	Indicated Rating
Arkansas Electric	A2 (a)	Stable	91%	Baa
Associated Electric	A1	Stable	100%	Aa
Basin Electric Power	A1	Stable	100%	Aa
Big Rivers Electric Corp.	(P) Baa1	Stable	100%	Aa
Buckeye Power	A1	Negative	100%	Aa
Chugach Electric Assoc.	A3 (b)	Stable	94%	Baa
Dairyland Power	A3 (c)	Negative	100%	Aa
Georgia Transmission	A3	Stable	100%	Aa
Golden Spread Electric	A3 (c)	Stable	90%	A
Great River Energy	A3	Stable	98%	A
Hoosier Electric Power	Baa1	RUR ↓	100%	Aa
Minnkota Power	Baa1 (c)	Stable	100%	Aa
Oglethorpe Power Corp.	A3	Negative	65%	A
Old Dominion Electric	A3	Stable	100%	Aa
PowerSouth	*Baa1 (c)*	*Stable*	*100%*	*Aa*
South Mississippi	A3	Stable	100%	Aa
Tri-State G&T Assoc.	Baa1	Stable	100%	Aa

[1] Ratings are senior secured unless otherwise noted.
(a) Secured Facility Bonds ranking junior to RUS security
(b) Senior Unsecured Rating; No secured debt in capital structure
(c) Issuer Rating

Factor 1: Observations and Outliers

The nature of the long-term wholesale power contracts taken together with regulatory status is one of the most important drivers of G&T co-op ratings, so it is not surprising that there are no negative outliers. All of the rated G&T co-ops score quite well with indicated ratings of Aa , A, or Baa. Two of the five positive outliers are directly attributable to comparison of the indicated rating for the sub-factor against an actual senior unsecured Issuer Rating and would not be outliers if compared to an implied senior secured rating one notch higher than the Issuer Rating. The high ratings that so many of the G&T co-ops receive for Factor 1 help offset weaker scores in other areas, especially in Factor 2.

Notwithstanding the solid indicated ratings for Factor 1, we draw attention to the following observations. The protection afforded by wholesale power supply contracts can be eroded by changes in the contracts over time, or more suddenly, due to a need for exceptionally large rate increases.

Under a strict interpretation of the definitions, Oglethorpe Power Corp. (OPC) would receive a Ba indicated rating for Factor 1. This strict interpretation results from the fact that OPC's owned resources are currently providing only about 65% of its members' power requirements. The situation results from a conscious decision by OPC's members to enter into power supply arrangements with third-party suppliers for their future incremental growth as permitted under the amended wholesale power supply contracts, extending through 2050. In Oglethorpe's case, we are not unduly concerned because its members remain joint and severally liable to pay all of the cooperative's costs and we believe Oglethorpe's stable supply of relatively affordable baseload power will become increasingly valuable to its members as their needs grow and they are continually forced to look for additional sources of supply. We believe an indicated rating of A more appropriately captures the degree of credit impact from the current relationships between OPC and its members when considered together with its rate autonomy.

Chugach Electric Association (CEA) is somewhat unique because it operates as a combined G&T co-op and distribution cooperative. As such, the 94% of its sales made to customers includes not only the 39% of energy sales made under wholesale power contracts, but also the 55% of energy sales made directly to retail customers under the tariff and certificated service territory in the state of Alaska. Moody's views direct retail revenues to commercial and residential customers to be of equal, if not somewhat better quality, than wholesale revenues derived from sales to member co-ops.

Factor 2: Ratings Mapping

The following table details the mapping for the Rate Flexibility factor:

Factor 2 (20%)
Rate Flexibility

Negative Outlier
Positive Outlier

G&T Co-op	Current Rating [1]	Outlook	Bd. Involve/ Adj. Mech.	Purchased Power/Total MWh Sales	Indicated Rating	New Build Exposure	Indicated Rating	Carbon Exposure	Rate Shock Exposure Indicated Rating
Arkansas Electric	A2 (a)	Stable	A	15%	Aa	107%	Ba	76%	Ba
Associated Electric	A1	Stable	Aa	12%	Aa	59%	Baa	80%	Ba
Basin Electric Power	A1	Stable	Aa	17%	Aa	152%	B	82%	Ba
Big Rivers Electric Corp.	(P) Baa1	Stable	Baa	101%	B	33%	A	89%	B
Buckeye Power	A1	Negative	Aa	8%	Aa	44%	A	90%	B
Chugach Electric Assoc.	A3 (b)	Stable	A	17%	Aa	78%	Ba	90%	B
Dairyland Power	A3 (c)	Negative	Aa	8%	Aa	42%	A	90%	B
Georgia Transmission	A3	Stable	Aa	N/A	N/A	51%	Baa	N/A	Aa
Golden Spread Electric	A3 (c)	Stable	Aa	85%	B	84%	Ba	100%	B
Great River Energy	A3	Stable	Aa	31%	Baa	76%	Ba	98%	B
Hoosier Electric Power	Baa1	RUR ↓	Baa	27%	A	64%	Baa	100%	B
Minnkota Power	Baa1 (c)	Stable	Aa	27%	A	106%	Ba	100%	B
Oglethorpe Power Corp.	A3	Negative	A	8%	Aa	115%	Ba	55%	Baa
Old Dominion Electric	*A3*	*Stable*	*A*	*54%*	*Ba*	*29%*	*A*	*67%*	*Baa*
PowerSouth	Baa1 (c)	Stable	Aa	38%	Baa	29%	A	100%	[illegible]
South Mississippi	A3	Stable	Aa	63%	B	76%	Ba	81%	Ba
Tri-State G&T Assoc.	Baa1	Stable	A	32%	Baa	83%	Ba	91%	B

[1] Ratings are senior secured unless otherwise noted.
(a) Secured Facility Bonds ranking junior to RUS security
(b) Senior Unsecured Rating; No secured debt in capital structure
(c) Issuer Rating

Factor 2: Observations and Outliers

Factor 2 contains the most outliers of any of the five key Factors, the substantial majority of which are negative outliers. In particular, over three-quarters of the rated universe are negative outliers for the Rate Shock Exposure sub-factor, largely reflecting the substantial dependence that the sector has on generation from carbon emitting fuels, especially coal. There are also seven negative outliers for the New Build Exposure sub-factor, reflecting the growing need for generating capacity and transmission infrastructure for those G&Ts as they have either grown into what excess capacity they previously had or are projecting growth in demand that exceeds current capabilities. In particular, Oglethorpe's New Build Exposure relates to its plans to participate in construction of a new nuclear plant, which contributed to the recent change in its rating outlook to negative from stable.

Big Rivers, Old Dominion, Golden Spread, and South Mississippi are all negative outliers for the sub-factor measuring Purchased Power as a Percentage of Sales. We anticipate that Big Rivers' outlier status will improve prospectively following the recently completed unwind transaction which re-establishes its direct rights to power produced from its generation assets previously leased to LG&E. Golden Spread's negative outlier status may also improve as it pursues construction of additional generation capacity. Old Dominion and South Mississippi may also seek to increase their respective owned generating capacity; however, in the near term we believe purchased power will remain integral to their resource strategy.

The low ratings for so many of the G&Ts relating to sub-factors in Factor 2 are largely balanced by higher scores in Factor 1 and Factor 4. The rate autonomy and relatively low rates for so many of the G&Ts make it more likely that the members will accept what in many instances will be the continuation of significant expected rate increases over the next several years even after a series of rate increases already implemented over the past few years.

The two positive outliers for the sub-factor relating to Board Involvement/Rate Adjustment Mechanisms are directly attributable to comparison of the indicated rating for the sub-factor against an actual senior unsecured Issuer Rating and would not be outliers if compared to an implied senior secured rating one notch higher than the Issuer Rating.

Factor 3: Ratings Mapping

The following table details the mapping for the Member Profile factor:

Factor 3 (10%) Member / Owner Profile					Negative Outlier / Positive Outlier	
G&T Co-op	Current Rating [1]	Outlook	Res. Sales/ Total Sales (%)	Indicated Rating	Mbrs. Equity / Capitalization (%)	Indicated Rating
Arkansas Electric	A2 (a)	Stable	50%	A	39%	Baa
Associated Electric	A1	Stable	71%	A	50%	A
Basin Electric Power	A1	Stable	36%	Ba	35%	Baa
Big Rivers Electric Corp.	(P) Baa1	Stable	18%	B	34%	Baa
Buckeye Power	A1	Negative	60%	A	50%	A
Chugach Electric Assoc.	A3 (b)	Stable	51%	A	43%	Baa
Dairyland Power	A3 (c)	Negative	70%	A	46%	Baa
Georgia Transmission	A3	Stable	70%	A	43%	Baa
Golden Spread Electric	A3 (c)	Stable	58%	A	45%	Baa
Great River Energy	A3	Stable	57%	A	45%	Baa
Hoosier Electric Power	Baa1	RUR ↓	65%	A	61%	Aa
Minnkota Power	Baa1 (c)	Stable	62%	A	45%	Baa
Oglethorpe Power Corp.	A3	Negative	68%	A	43%	Baa
Old Dominion Electric	A3	Stable	63%	A	36%	Baa
PowerSouth	Baa1 (c)	Stable	69%	A	47%	Baa
South Mississippi	A3	Stable	65%	A	53%	A
Tri-State G&T Assoc.	Baa1	Stable	33%	Ba	49%	Baa

[1] Ratings are senior secured unless otherwise noted.
(a) Secured Facility Bonds ranking junior to RUS security
(b) Senior Unsecured Rating; No secured debt in capital structure
(c) Issuer Rating

Factor 3: Observations and Outliers

Indicated ratings for Factor 3 map reasonably well to the actual ratings for each of the 17 rated G&T co-ops in this methodology, with just one positive outlier and two negative outliers.

Basin Electric Power Cooperative and Big Rivers are negative outliers for residential sales as a percentage of total sales to retail customers. In Basin Electric's case this is primarily because of the relatively high percentage of sales that Basin makes to non-members due to excess generation capacity. Importantly, off-system sales to non-members have served Basin well through the years and has enabled Basin to avoid member rate increases that otherwise would have been needed to meet financial covenants. Basin's demand growth from its members in recent years has enabled it to grow into some of its excess capacity. As Basin's sales to members continue to increase and off-system sales decline, the percentage of residential sales should continue to increase as it has over the past few years, albeit remaining an outlier. Big Rivers' negative outlier status is directly attributable to the high concentration of sales that its largest member/owner, Kenergy, makes to two aluminum smelters.

The lone positive outlier for Factor 3 relates to Hoosier Electric's members' consolidated equity as a percentage of equity. This status is more a function of the recent downgrade of Hoosier's rating than any noteworthy strengthening of the equity portion of total capitalization.

Factor 4: Ratings Mapping

The following table details the mapping for the Financial Metrics factor:

Negative Outlier
Positive Outlier

G&T Co-op	Current Rating [1]	Outlook	TIER	Indicated Rating	DSC	Indicated Rating	FFO / Debt	Indicated Rating	FFO / Interest	Indicated Rating	Equity/ Total Cap.	Indicated Rating
Arkansas Electric	A2 (a)	Stable	1.31x	A	1.19x	Baa	9%	A	2.6x	Aa	40%	Aa
Associated Electric	A1	Stable	1.29x	A	1.27x	A	6%	A	2.1x	A	20%	Baa
Basin Electric Power	A1	Stable	2.23x	Aaa	1.50x	Aa	10%	Aa	3.0x	Aa	30%	A
Big Rivers Electric Corp.	(P) Baa1	Stable	1.51x	Aa	1.54x	Aa	6%	Baa	1.9x	Baa	-18%	B
Buckeye Power	A1	Negative	1.36x	A	1.36x	A	7%	A	2.6x	Aa	26%	A
Chugach Electric Assoc.	A3 (b)	Stable	1.25x	A	1.84x	Aa	11%	Aa	2.6x	Aa	29%	A
Dairyland Power	A3 (c)	Negative	1.00x	Ba	1.04x	Ba	3%	Baa	1.6x	Baa	12%	Baa
Georgia Transmission	A3	Stable	1.19x	Baa	1.09x	Ba	4%	Baa	1.9x	Baa	10%	Baa
Golden Spread Electric	A3 (c)	Stable	5.02x	Aaa	3.93x	Aaa	31%	Aaa	5.7x	Aaa	51%	Aaa
Great River Energy	A3	Stable	1.34x	A	1.12x	Baa	7%	A	2.4x	A	13%	Baa
Hoosier Electric Power	Baa1	RUR ↓	1.40x	A	1.37x	A	8%	A	2.5x	Aa	13%	Baa
Minnkota Power	Baa1 (c)	Stable	1.17x	Baa	1.11x	Baa	5%	Baa	2.0x	A	36%	Aa
Oglethorpe Power Corp.	A3	Negative	1.07x	Ba	1.09x	Ba	6%	Baa	1.9x	Baa	11%	Baa
Old Dominion Electric	A3	Stable	1.28x	A	1.46x	Aa	7%	A	2.2x	A	24%	A
PowerSouth	Baa1 (c)	Stable	1.34x	A	1.20x	A	5%	Baa	2.1x	A	10%	Baa
South Mississippi	A3	Stable	1.36x	A	1.18x	Baa	7%	A	2.3x	A	14%	Baa
Tri-State G&T Assoc.	Baa1	Stable	1.72x	Aaa	1.13x	Baa	8%	A	2.8x	Aa	15%	Baa

[1] Ratings are senior secured unless otherwise noted.
(a) Secured Facility Bonds ranking junior to RUS security
(b) Senior Unsecured Rating; No secured debt in capital structure
(c) Issuer Rating

Factor 4: Observations and Outliers

Factor 4 takes into account historical financial statements. Historic results help us to understand the pattern of a G&T's financial and operating performance and how the G&T compares to its peers. While Moody's rating committees and the rating process use both historical and projected financial results, this document makes use only of historic data, and does so solely for illustrative purposes.

Although a significant number of the sub-factors in Factor 4 map reasonably well to a G&T's actual rating, there are several instances where positive outlier status is evident. Most notably, Golden Spread is a positive outlier for all its key metrics, reflecting conservative financing strategies through the years. We expect that this situation will begin to change over the next several years as Golden Spread begins to rely on debt financing to fund its investment in new generation capacity. Other positive outliers for various metrics include Basin Electric, Big Rivers, Hoosier Energy, Minnkota Power, and Tri-State G&T Association. The strength of these scores helps balance the weaker scores these G&Ts have in Factor 2, especially as it relates to Rate Shock Exposure and New Build Exposure.

Georgia Transmission Corporation, Oglethorpe Power Corporation, and Dairyland Power are negative outliers on TIER and/or DSC, reflecting greater acceptance by their respective management and boards to manage results close to the minimum required levels contained in their debt indentures. Big Rivers is a negative outlier for equity as a percentage of Total Capitalization, reflecting its negative net worth that has prevailed for many years following approval of its plan of reorganization when it emerged from bankruptcy proceedings. The negative outlier status will eventually become a moot point as the G&T's net worth turns substantially positive following completion of the company's unwind transaction.

Factor 5: Ratings Mapping

The following table details the mapping for the Size factor:

Factor 5 (10%)
G&T Size

Negative Outlier
Positive Outlier

G&T Co-op	Current Rating [1]	Outlook	Megawatt Hour Sales (Millions)	Indicated Rating	Net PP&E ($ Billions)	Indicated Rating
Arkansas Electric	A2 (a)	Stable	13.2	A	$0.80	Baa
Associated Electric	A1	Stable	23.4	Aa	$1.69	A
Basin Electric Power	A1	Stable	19.5	A	$2.41	Aa
Big Rivers Electric Corp.	(P) Baa1	Stable	5.2	Baa	$0.91	Baa
Buckeye Power	A1	Negative	9.1	Baa	$1.22	A
Chugach Electric Assoc.	A3 (b)	Stable	2.8	B	$0.46	Baa
Dairyland Power	A3 (c)	Negative	6.7	Baa	$0.97	Baa
Georgia Transmission	A3	Stable	N/A	N/A	$1.49	A
Golden Spread Electric	A3 (c)	Stable	7.6	Baa	$0.20	B
Great River Energy	A3	Stable	15.0	A	$2.08	Aa
Hoosier Electric Power	Baa1	RUR ↓	10.9	Baa	$0.80	Baa
Minnkota Power	Baa1 (c)	Stable	4.9	Ba	$0.24	B
Oglethorpe Power Corp.	A3	Negative	23.3	Aa	$3.64	Aa
Old Dominion Electric	A3	Stable	10.0	Baa	$1.02	A
PowerSouth	Baa1 (c)	Stable	9.0	Baa	$1.23	A
South Mississippi	A3	Stable	9.9	Baa	$0.79	Baa
Tri-State G&T Assoc.	Baa1	Stable	19.0	A	$2.57	Aa

[1] Ratings are senior secured unless otherwise noted.
(a) Secured Facility Bonds ranking junior to RUS security
(b) Senior Unsecured Rating; No secured debt in capital structure
(c) Issuer Rating

Factor 5: Observations and Outliers

Even the largest G&T co-op, Oglethorpe Power Corporation, is considered to be relatively small by investor-owned electric utility standards, so it is not surprising that there is only one positive outlier in Key Factor 5. The three negative outliers are Chugach Electric, Golden Spread, and Minnkota, reflecting smaller than average size for the rated universe.

There are offsetting considerations in these three cases that merit comment. Although Chugach Electric is a negative outlier for megawatt hours sold it is by far the largest power provider in the state of Alaska and is geographically isolated, which tends to temper concern about its small size. In the case of Golden Spread and Minnkota, there are large capital programs under way, which over time may mitigate their respective negative outlier status for net property, plant and equipment.

APPENDIX D: G&T Co-op Industry Overview

G&T co-ops represent one of the three main forms of ownership for enterprises involved in the generation and delivery of electricity. Investor owned utilities (IOUs) constitute a sizeable majority of the U.S. electricity sector, with government owned municipal or public power entities representing the second largest segment of the market, and G&T co-ops being by far the smallest segment. G&T co-ops do not directly compete with each other or with investor owned utilities or government owned entities in a substantial way because cooperatives mainly provide service to their owner members under long term all requirements power contracts.

The A2 average (senior most) rating assigned for G&T co-ops equals the average rating for municipal or public power entities, and is two notches higher than the Baa1 average rating for (IOUs). G&T co-ops tend to be significantly smaller than investor owned utilities but have higher ratings because they are able to raise rates without the regulatory review required for investor owned utilities. G&T co-ops also face less competition given their contractual relationship with their member owners.

The following chart compares some of the characteristics that distinguish the risk profiles of these three subsets of the U.S. power sector.

Investor Owned Utilities	G&T Co-ops	Municipal and Public Power
Rate regulated	Most are not rate regulated but their owners may be	Not rate regulated
Profit seeking; operated for the benefit of public shareholders with obligations to serve regulated ratepayers	Not-for-profit; operated for the benefit of their owner members	Operated for public benefit for the region served
Most are larger; may have multiple entities in an issuer family	All are small relative to IOUs	Most are small relative to IOUs
Subject to competition in the wholesale market; sometimes in the retail market	Little competition	Little competition
Some history of defaults, usually as a result of needing rate increases that are too large to be acceptable to ratepayers	Some history of defaults; usually due to need for rate increases that are too large to be acceptable to members	Defaults have been extremely rare
Can file Chapter 11 bankruptcy	*Can file Chapter 11 bankruptcy*	*More impediments to bankruptcy* but may be able to file Chapter 9
Tend to have higher rates compared to municipal or public power	Rates tend to be comparable to IOUs	Tend to have lower rates than G&T co-ops and IOUs
Rely extensively on capital markets	*Most borrow from the Rural Utilities* Service and cooperative financial institutions; larger issuers access the capital markets	Rely on public and private markets for financing needs; may have access to government funding if needed

Comparison with Joint Power Agencies

Moody's rates approximately $35 billion of bonds issued by Joint Power Agencies (JPAs), which have some *characteristics in common with electric generation and transmission cooperatives.* Both are nonprofit enterprises and are governed by their members. Cooperatives as well as many JPAs serve small rural communities in the U.S. A significant difference between the two is the greater ability of JPAs to issue low cost tax-exempt debt, although cooperatives may borrow at below market rates through the federal Rural Utilities *Service.*

Since the 1970's, groups of city-owned electric utilities have established JPAs to pool resources to finance the construction of new generation facilities or to jointly purchase electric power supply. Participating members of

JPAs are contractually obligated for power supply through take-or-pay and take-and-pay power sales agreements. These agreements are the underlying security for tax-exempt debt issued by JPAs. The power sales agreements are structured to have the same term as the debt issue.

JPAs have unregulated rate-setting authority and their municipal utility participants can recover costs by independently raising retail rates. The current median municipal scale rating of JPAs is A2. After a period of low debt issuance, JPAs have accelerated the pace of borrowing to finance ownership in new generation plants in order to assist their participant members in meeting demand growth and also to diversify their generation fuel mix.

The key rating factors Moody's considers for JPA ratings include municipal utility participant credit quality, pricing power and market position, as well as governance structure and management abilities of these public sector organizations. Financial position, capital spending, and structural features of borrowing instruments are also important. Key questions embedded in our analysis of these factors are:

- How economic are power sales contracts relative to competitors?
- How are the power supply contracts structured, and what are the bond security provisions?
- What is the average weighted credit quality of participants? What are the demographic and economic characteristics of the service areas of the participating municipal electricity distributors?
- How do JPAs manage their balance sheet and plan for capital spending in order to position the JPA to meet future demand growth and competition?

The price of power the JPA supplies, and the reliability of the power supply, are among the most significant drivers of JPA credit ratings given the importance of these factors to their municipal utility participants. JPAs with the highest cost power are generally rated lower than those with more competitive price structures.

APPENDIX - E

Key Rating Issues over the Intermediate Term

Global Climate Change and Environmental Awareness

There have been significant increases in environmental expenditure estimates among G&T co-ops with significant coal fired generation in recent years as policymakers have mandated pollution control measures and emissions limitations in response to public concerns over carbon. These expenditures are likely to continue to increase with the imposition of new and sometimes uncertain requirements with respect to carbon emissions. G&T co-ops may have to implement substantial additional reductions in power plant emissions and could experience progressively higher capital expenditures over the next decade. In the U.S., the planned construction of several new coal plants have been cancelled or at least delayed as a result of opposition from regulators, political leaders, and the public or because cheaper alternatives appeared more compelling due to the significant increase in coal plant construction costs.

Large Capital Expenditures and Rising Costs for New Generation and Transmission

In order to meet rising electricity demand as the U.S. slowly emerges from a recession, many G&T co-ops intend to purchase generating plants or plan to build additional peaking and base load generating capacity, while correspondingly taking steps to upgrade and/or add to transmission infrastructure. As of end of 2008, the aggregate net property plant and equipment for rated G&T co-ops was approximately $12 billion with about an additional $8 billion of capital expenditures planned over the next five years. For those G&Ts that elect to participate in the construction of large, highly capital intensive nuclear plants, which have not been built in the U.S. in many years, the challenges could be particularly daunting and significantly pressure their credit quality.

Larger Rate Increases May Test Members' Willingness To Raise Rates

After a period of rate stability or rate decline throughout the 1980's and 1990's, G&T co-ops are increasing the wholesale rates that they charge their members. The impact of higher prices for fuel and purchased power has not been fully experienced by member co-ops because some purchase contracts have not yet been reset to new market levels.

G&Ts will likely impose large rate increases on co-op members when the G&T's power purchase contracts expire if that coincides with a period of rising market prices or when a large new generating plant is being constructed. Very large increases could test the willingness of members to pay higher rates.

G&Ts who choose to defer increasing rates to their members in the face of sharply higher costs or who are unable to gain approval from regulators to do so when rate regulation applies will likely experience a deterioration in their key credit metrics. Inability to obtain regulatory approval for rate increases has contributed to the bankruptcy of G&T co-ops in the past. As an alternative to imposing a large rate increase at one time, most G&T co-ops try to pursue a strategy of smaller, more frequent rate increases to be phased in over a period of years.

Rates charged by G&T co-ops need to be regionally competitive with rates charged by other power providers. Rate competitiveness of G&T co-ops relative to other power providers is important because it affects the willingness of co-op members to accept rate increases when costs increase. With most other power providers currently facing similar commodity cost volatility and capital spending requirements, as well as more expensive insurance and pension benefits, we do not expect that the rates that G&T co-ops charge their members will be less competitive than those charged by other power providers.

Reliance on Low-Cost Loans from U.S. Government Sponsored Agencies

G&T co-ops rely heavily on low cost loans from the Rural Utilities Service of the U.S. Department of Agriculture (RUS) and from RUS guaranteed loans provided by the Federal Financing Bank (FFB), a government funding arm.

In addition to the RUS, G&T co-ops also rely heavily on loans provided by cooperative financial institutions such as the National Rural Utilities Cooperative Finance Corporation (CFC; A1 senior secured; stable outlook) and CoBank, and local commercial banking institutions.

The RUS is the single largest provider of debt financing to the sector. Given the history of political support for the RUS loan program, our ratings reflect our assessment that the probability of systemic withdrawal of such low cost funding is low. The ratings do, however, incorporate the RUS decision not to provide loans for the construction of base load coal and nuclear plants.

Some cooperatives have elected to repay all RUS loans or otherwise obtain lien accommodations in order to obtain more financial flexibility, which results in a greater reliance upon the capital markets as a source of funding. However, the RUS requires that some of its borrowers obtain at least 30% of their financing from other sources. Larger G&T co-ops, such as those in Moody's rated universe, have sought to increase financial flexibility by accessing the capital markets. We anticipate that more G&T co-ops will do likewise in the future given the RUS decision not to lend for the construction of base load coal and nuclear plants.

Moody's Related Research

Industry Outlooks:

- U.S Regulated Electric Utilities, Six-Month Update, July 2009 (118776)
- U. S. Investor-Owned Electric Utility Sector, January 2009 (113690)
- EMEA Electric and Gas Utilities, November 2008 (112344)
- North American Natural Gas Transmission & Distribution, March 2009 (115150)

Rating Methodologies:

- Regulated Electric and Gas Utilities (118481)
- Unregulated Utilities and Power Companies, August 2009 (118508)
- Regulated Electric and Gas Networks, August 2009 (118786)
- Moody's Approach to Global Standard Adjustments in the Analysis of Financial Statements for Non-Financial Corporations - Part I, July 2005 (93570)

Special Comments:

- Credit Roadmap for Energy Utilities and Power Companies in the Americas, March 2009 (115514)
- Carbon Risks Becoming More Imminent for U.S. Electric Utility Sector (115175)
- New Nuclear Generation: Ratings Pressure Increasing (117883)

To access any of these reports, click on the entry above. Note that these references are current as of the date of publication of this report and that more recent reports may be available. All research may not be available to all clients.

U.S. Electric Generation & Transmission Cooperatives

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